Direct Testimony and Schedules
Levi A. Peterson

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power
For Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E015/GR-26-199

Exhibit ____

JURISDICTIONAL COSTS, CLASS COST OF SERVICE STUDY, AND COST RECOVERY RIDERS

November 2, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Levi A. Peterson, and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc., doing business as Minnesota Power ("Minnesota Power" or the "Company"). My current position is Cost Pricing Analyst II.

Q. Please summarize your qualifications and experience.

A. I hold a Bachelor of Business Administration in Economics with a minor in Accounting from the University of Minnesota Duluth, and a Master of Science in Data Science from Eastern University. In my current role, I am responsible for delivering analytical support, developing studies, and executing calculations to support Minnesota Power's fair and accurate recovery of costs through regulatory proceedings. This work includes contributions to the rate case filed by Minnesota Power in 2023 (Docket No. E015/GR-23-155) (the "2023 Rate Case"), Longspur Wind Project (Docket No. E015/M-25-309), Iron Range – St. Louis County – Arrowhead 345 kilovolt ("kV") Transmission Line Project Certificate of Need (Docket No. E015/CN-25-111), and Maple River – Cuyuna 345 kV Transmission Project Certificate of Need (Docket No. E015/CN-25-109) proceedings. I also provide annual support for the Midcontinent Independent System Operator's ("MISO") cost recovery process, as well as a number of other filings.

Q. What is the purpose of your testimony?

A. I present the methodology of Minnesota Power's 2027 Class Cost of Service Study ("CCOSS"). I address compliance matters related to Minnesota Power's 2009 Rate Case (Docket No. E015/GR-09-1151) and Federal Energy Regulatory Commission ("FERC") Order No. 898. My testimony summarizes the process of jurisdictional separation of costs, the functional assignment and classification of costs, and the allocation of costs to customer classes, including the development of allocation factors used in the CCOSS. Additionally, I discuss a change to the CCOSS related to the

classification of meter costs, and I discuss the proposed treatment of the Company's current cost recovery riders in this case.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section II addresses compliance matters related to Minnesota Power's 2009 Rate Case and FERC Order No. 898;
- Section III addresses the results of the CCOSS, classification and cost allocation methodologies, and a change to the classification of meter costs in the CCOSS;
- Section IV summarizes the methodology of separating jurisdictional costs;
- Section V summarizes the methodology to allocate costs to retail customer classes and various analyses used in the CCOSS; and
- Section VI addresses Minnesota Power's proposed treatment of our current cost recovery riders in this rate case as well as a proposed alternative cost recovery mechanism for dewatering costs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the two following schedules to my Direct Testimony:

- MP Exhibit ___ (Levi Peterson), Direct Schedule 1 – Guide to Minnesota Power's CCOSS; and
- MP Exhibit ___ (Levi Peterson), Direct Schedule 2 – Comparison of Jurisdictional Allocation Factors.

Q. Are there any other schedules in the rate filing that support the recommendations in your testimony?

A. Yes. My testimony is supported by a variety of exhibits in Volumes 1, 3, and 4 including:

- Direct Schedule B-11 (IR) – Interim Rate Increase – Net of Riders
- Direct Schedule E-3 – Class-Cost-of-Service Study
- Workpaper AF-1 – 2027 Jurisdictional Demand and Energy Allocation Factors
- Workpaper AF-2 – 2026 Jurisdictional Demand and Energy Allocation Factors

- Workpaper AF-3 – 2025 Jurisdictional Demand and Energy Allocation Factors
- Workpaper AF-4 – 2027 Jurisdictional & Class Customer Allocation TS
- Workpaper AF-5 – 2026 Jurisdictional & Class Customer Allocation TS
- Workpaper AF-6 – 2025 Jurisdictional & Class Customer Allocation TS
- Workpaper OS-1 – Distribution Plant Study
- Workpaper OS-2 – Lead Lag Study

II. COMPLIANCE MATTERS

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I address CCOSS-related compliance requirements arising from Minnesota Power's 2009 Rate Case and FERC Order No. 898. Specifically, I address the requirement in Order Point 20 from Minnesota Power's 2009 Rate Case, which required in future rate case filings that Minnesota Power conduct any CCOSS by calculating and assigning income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS.[1] I also address the changes to FERC accounts per FERC Order No. 898.

Q. Has Minnesota Power complied with Order Point 20 from the 2009 Rate Case?

A. Yes. Order Point 20 required that Minnesota Power conduct any CCOSS by calculating and assigning income taxes by class based on the adjusted net taxable income by class as determined by the CCOSS in all future rate cases. The Company has complied with this Order Point in all rate cases subsequent to the 2009 Rate Case. Similarly, the CCOSS submitted for this case calculates and assigns income taxes by classification and customer class based on the adjusted net taxable income by classification and customer class as determined by the CCOSS in compliance with Minnesota Public Utilities Commission ("Commission") requirements.

[1] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 71 at Order Point 20 (Nov. 2, 2010) (eDocket No. 201011-56128-01).

Q. Has Minnesota Power complied with FERC Order No. 898?

A. Yes. FERC Order 898 added dedicated accounts for items such as energy storage, renewables, and communication equipment. The Company's accounting records and CCOSS have been updated to reflect the changes in FERC accounts and ensure compliance. For more detailed information, please refer to MP Exhibit ___ (Levi Peterson), Direct Schedule 1.

Q. Do the changes resulting from FERC Order No. 898 impact the CCOSS allocation methodology?

A. No. FERC Order No. 898 made changes to the Uniform System of Accounts and associated accounting and reporting requirements. Those accounting changes required Minnesota Power to update the FERC accounts reflected in its accounting records and CCOSS, but Order 898 did not require Minnesota Power to change the classification or allocation methodologies used in the Company's CCOSS.

III. CCOSS MODEL

A. CCOSS Results

Q. Please provide an overview of the final allocation of revenue requirement to customer class for adjusted test year 2027 general rates based on the CCOSS.

A. The results of the CCOSS at a class level are summarized in Table 1 below and also found in Volume 3, Schedule E-3. These CCOSS results indicate the change from present rates that would be necessary for each class to cover its respective cost of service as determined by the CCOSS.

Table 1. Adjusted Test Year 2027 CCOSS Required Revenue Increase by Customer Class Including Dual Fuel

Required Increase (Decrease)	$	%
Residential	$102,664,068	69.61%
General Service	$26,185,875	26.50%
Large Light & Power	$20,185,673	14.61%
Large Power	$16,478,741	4.51%
Lighting	$1,100,290	24.80%
Total	**$166,614,646**	**22.09%**

Q. Can you provide some context for these results?

A. Yes. First, the increase for the Residential class reflects the cumulative effect of prior rate case outcomes, and not a sudden change in the cost of serving that particular class. As the Residential class's rate design has previously been set below the cost of service, the 69.61 percent increase shown above is representative of the combined impact of a general increase in costs, as well as an increase to make up for the class's previous gap between rate design and cost of service.

Second, as shown in Schedule B-11 (IR), $9.2 million (MN Jurisdiction) for the Duluth Loop Reliability Project was already approved for recovery through the Transmission Cost Recovery Rider ("TCR") and does not represent a total increase in costs for customers, but it is a shift in where those costs are being recovered. Similarly, the resetting of Production Tax Credits ("PTCs") accounts for $23 million (MN Jurisdiction) of the increase shown above. For more information about the resetting of PTCs, please refer to Section VI of my testimony.

Finally, the MN jurisdictional test year revenue requirement and allocations are impacted by the planned wholesale load associated with Mesabi Metallics, which is served through the City of Nashwauk. Due to the large wholesale load anticipated in 2027, costs are shifted out of the Retail jurisdiction.

Q. How does Minnesota Power propose to use these CCOSS results?

A. The above results demonstrate the class cost revenue requirement outcomes by class. These results show the change from present rate revenues that would be required for each class to cover its respective cost of service as determined by the CCOSS. Table 2 below shows the total class revenue requirements by customer, demand, and energy classifications. Table 3 below shows the total class revenue requirements by function and classification. Minnesota Power considers the resulting class cost revenue requirements by function and classification components to be the appropriate starting points for rate design.

Table 2. 2027 Adjusted Test Year Class Revenue Requirements by Classification Including Dual Fuel

Revenue Requirements	Total	Customer	Demand	Energy
Residential	$250,142,745	$64,973,339	$132,233,373	$52,936,033
General Service	$124,982,415	$11,865,538	$79,908,940	$33,207,937
Large Light & Power	$158,371,994	$885,235	$102,653,031	$54,833,728
Large Power	$381,689,416	$465,808	$223,533,834	$157,689,773
Lighting	$5,536,744	$4,258,764	$829,574	$448,406
Total	**$920,723,314**	**$82,448,683**	**$539,158,752**	**$299,115,879**

Table 3. 2027 Adjusted Test Year Class Revenue Requirements by Function and Classification Including Dual Fuel

Revenue Requirements	Minnesota Jurisdiction	Residential	General Service	Large Light & Power	Large Power	Lighting
Production						
Customer	$139,434	$107,664	$21,296	$1,177	$993	$8,303
Demand	$318,241,714	$67,289,894	$37,372,621	$54,437,034	$158,662,675	$479,490
Energy	$299,115,879	$52,936,033	$33,207,937	$54,833,728	$157,689,773	$448,406
Subtotal Production	617,497,026	120,333,592	70,601,854	109,271,940	316,353,442	936,199
Transmission						
Demand	$118,797,343	$19,564,628	$13,476,485	$21,219,148	$64,426,165	$110,918
Subtotal Transmission	118,797,343	19,564,628	13,476,485	21,219,148	64,426,165	110,918
Distribution Bulk Delivery						
Demand	$22,414,882	$8,061,826	$6,363,814	$7,487,529	$444,995	$56,718
Subtotal Dist Bulk Delivery	22,414,882	8,061,826	6,363,814	7,487,529	444,995	56,718
Distribution Primary						
Customer	$20,353,002	$16,438,598	$2,986,624	$62,076	$0	$865,704
Demand	$52,003,083	$20,150,404	$15,661,828	$16,049,020	$0	$141,831
Subtotal Dist	72,356,085	36,589,001	18,648,452	16,111,096		1,007,536
Distribution Secondary						
Customer	$27,074,479	$19,791,252	$3,867,681	$108,799	$0	$3,306,748
Demand	$27,701,730	$17,166,621	$7,034,191	$3,460,301	$0	$40,617
Subtotal Dist Secondary	54,776,210	36,957,873	10,901,873	3,569,099		3,347,365
Meters						
Customer	$14,657,318	$11,195,432	$2,825,845	$183,370	$420,679	$31,993
Subtotal Meters	14,657,318	11,195,432	2,825,845	183,370	420,679	31,993
Customer Services						
Customer	$20,224,450	$17,440,393	$2,164,092	$529,814	$44,136	$46,015
Subtotal Customer Services	20,224,450	17,440,393	2,164,092	529,814	44,136	46,015
Total	**$920,723,314**	**$250,142,745**	**$124,982,415**	**$158,371,994**	**$381,689,416**	**$5,536,744**

The revenue requirements provide direction for rate design that would result in customer rates and cost recovery that are more closely aligned with cost causation, resulting in a reasonable, fairer, and more equitable overall cost for each class. The Company's

proposed rate design for this proceeding is discussed in more detail in the Direct Testimony of Company witness Leah N. Peterson.

Q. Does Minnesota Power's CCOSS provide a reasonable basis for establishing rates in this case?

A. Yes. Minnesota Power's proposed CCOSS provides reasonable and equitable estimates of the overall contribution made by each customer class to the cost of service based on sound cost causation principles and supports the rate design presented by Company witness Leah N. Peterson.

Q. Did Minnesota Power generate and include other CCOSS results apart from the 2027 test year General Rates shown above?

A. Yes, several other CCOSS results were generated, including Interim Test Year 2027 CCOSS, Unadjusted Test Year 2027 CCOSS, Projected Fiscal Year 2026 CCOSS, and Most Recent Fiscal Year 2025 CCOSS. These results are included in Volume 4, Workpapers, COS-1 to COS-4. The various ratemaking adjustments incorporated into the General Rate CCOSS and the Interim Rate CCOSS are discussed in the Direct Testimony of Company witness Amanda L. Turner.

B. Classification and Cost Allocation Methodologies

Q. Does Minnesota Power's 2027 CCOSS use the same classification and cost allocation methodologies affirmed or ordered by the Commission in Minnesota Power's 2023 Rate Case?

A. Yes. Apart from implementing a change to the classification of meter costs as discussed below, the CCOSS in the present filing uses the same classification and cost allocation methodologies as the Company's CCOSS in its 2023 Rate Case. Support for these methodologies can also be found in Minnesota Power's most recent fully litigated rate case (Docket No. E015/GR-21-335) ("2021 Rate Case"), in which the Commission concurred with the Administrative Law Judge's ("ALJ") findings and affirmed the

Company's classification and allocation of fixed production costs[2] and transmission costs.[3] Additionally, the Commission concurred with the ALJ's finding that the Company's classification and allocation of distribution costs using the Minimum System method was among a range of methods that are analytically sound and supported by the record.[4] Lastly, the Commission concurred with the ALJ that the Company's E8760 allocator remains the best method for allocating energy costs.[5]

C. Change to the Classification of Meter Costs

Q. What is the purpose of this section of your testimony?

A. In this section, I identify a change to the classification methodology of Advanced Metering Infrastructure ("AMI") meter costs in the CCOSS that makes it more accurate and reflective of the principle of cost causation.

Q. How do you recommend that AMI meter costs be classified?

A. I recommend that meter costs be classified as 100 percent Customer-related.

Q. Please provide some history regarding how meters have been classified in the past.

A. Meter costs are currently classified as one-third Demand-related, one-third Energy-related, and one-third Customer-related. At the same time, the Commission has recognized that advanced metering can have an important role in helping to manage energy consumption and customer demand, but that further analysis would be needed to move away from the long-standing practice of classifying all meters as Customer-related. Therefore, in the Company's 2021 Rate Case the Commission retained the practice of treating meter costs as Customer-related, but directed that in the Company's next case Minnesota Power should either analyze how AMI meters are associated with customer

[2] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 55 (Feb. 28, 2023) (eDocket no. 20232-193486-01). Fixed production costs were classified as 100 percent demand and allocated to class on the 4 Coincident Peak ("4CP") Average and Excess method.
[3] *Id.* at 57. Transmission costs were classified as 100 percent demand and allocated on the 12 Coincident Peak ("12CP") method.
[4] *Id.* at 58. The other method included in the range for classifying and allocating distribution costs was the basic customer method that the Company did not support.
[5] *Id.* at 63.

costs as well as energy and demand costs, or in the alternative in its CCOSS classify AMI meters equally to customer, demand, and energy costs. [6]

Given the timing of the Commission's initial order in the 2021 Rate Case and further reconsideration clarifying that order, in the 2023 Rate Case, Minnesota Power simply classified AMI metering costs as 1/3 Energy-related, 1/3 Demand-related, and 1/3 Customer-related. The settlement of that proceeding did not change that outcome.

Q. Why do you recommend that meter costs be classified as Customer-related?

A. Meter costs should be classified as Customer-related because the primary cost driver is the number of customers served. A utility installs meters because it has added a customer to the system, not because of energy usage or an increase in the system peak. This is consistent with the principle of cost causation as outlined in the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual (Chapter 6, page 87).

Table 4. Allocation Impact of Meter Classification Methodology

Revenue Requirements	1/3, 1/3, 1/3	100% Customer
Residential	$244,501,937	$250,142,745
General Service	$124,171,510	$124,982,415
Large Light & Power	$159,946,174	$158,371,994
Large Power	$386,574,213	$381,689,416
Lighting	$5,529,441	$5,536,744
Total	**$920,723,275**	**$920,723,314**

Additionally, as shown above in Table 4, classifying part of the meter costs as Energy-related and Demand-related shifts the allocation to rate classes in an asymmetric way. The altered classification methodology increases the costs assigned to high load factor customers, who tend to bear more than their share of the actual cost of their meters in any event. Furthermore, this is an incorrect portrayal of costs because it assumes meter costs rise and fall with energy usage or system peaks and not the number of customers.

[6] *Id*. at 61.

This is a matter of fundamental logic, as opposed to a mathematical exercise. Unless a customer is added to the system or discontinues electric service altogether, the number and cost of meters do not change due to customers increasing or decreasing conservation or consumption based on data from those meters. This distinction matters because the fundamental principle of a meaningful CCOSS is cost causation, not benefit allocation.

Q. Why is it important to focus on cost causation?

A. Minnesota Power's CCOSS focuses on allocating costs based on cost causation. The CCOSS serves as the foundation for rate design, and the integrity of it depends on a faithful representation of how costs are actually incurred. Altering the classification of costs without evidence that the cost of the AMI meter itself is driven by consumption or demand undermines the integrity of the analysis and increases the risk of cross-subsidization even before the Commission considers rate design principles. A sound CCOSS that does not embed cross-subsidization remains critically important to good decision-making.

Q. Does this change to the classification of meter costs impact Interim Rates?

A. No. The Company's Interim Rates will be set with meter costs classified as one-third Demand-related, one-third Energy-related, and one-third Customer-related, following the rate design from the Company's prior rate case.

IV. SEPARATION OF JURISDICTIONAL COSTS

Q. Please describe the process used to determine the separation of jurisdictional costs.

A. The process used to determine the separation of jurisdictional costs involves three steps that are common to all CCOSSs: functionalization, classification, and allocation. As shown below, costs are first assigned to major functions. Then, these costs and other expenses are allocated to classification and customer class, including the FERC jurisdiction, based on allocation factors.

Production

1. Steam
2. Hydro
3. Wind
4. Solar

Transmission

5. Transmission Production
6. Transmission

Distribution

7. Distribution - Primary Overhead Lines
8. Distribution - Primary Underground Lines
9. Distribution - Secondary Overhead Lines
10. Distribution - Secondary Underground Lines
11. Distribution - Secondary Overhead Transformers
12. Distribution - Secondary Underground Transformers
13. Distribution - Secondary Overhead Services
14. Distribution - Secondary Underground Services
15. Distribution - Secondary Leased Property
16. Distribution - Secondary Street Lighting
17. Distribution - Meters
18. Distribution - Customer Prem - EV Charger
19. Distribution - Other Distribution Production
20. Distribution - Other Distribution Bulk Delivery
21. Distribution - Other Distribution Bulk Delivery Specific Assignment
22. Distribution - Other Distribution Primary Specific Assignment

General Plant

Intangible Plant

Customer Services

Q. Please describe these major functions.

A. The Production function includes Minnesota Power's steam, hydroelectric, wind, and solar generating facilities. The Transmission function includes the costs associated with 69 kilovolt ("kV") and above transmission lines and substations. The Distribution function has several sub-functions that are subdivided into Primary and Secondary, Overhead and Underground, Meters, EV Charger, Distribution Production, and Distribution Bulk Delivery. The Distribution Bulk Delivery sub-function relates to 46 kV, 34 kV, and 23 kV facilities.

Any cost item other than Production, Transmission, and Distribution plant in service described above was assigned to a specific classification or function according to an analysis of the individual components making up the cost item or was assigned on the basis of related items in plant and internally generated allocation factors.

Q. Please describe the Demand, Energy, and Customer classification components.

A. Demand-related costs include those rate base and expense items that relate to demands coincident with the system peak or annual maximum non-coincident demands and include most Production costs, all Transmission costs, and all Distribution Bulk Delivery costs. Some Production costs include both Demand-related and Energy-related costs. The Energy-related Production costs consist of fuel and purchased power energy, reservoirs for Minnesota Power's hydroelectric generating stations, fuel inventory, and operations and maintenance ("O&M") expenses charged to FERC Accounts 501, 510, 512, 513, 543, 544, and 545.

Customer-related costs include rate base and expense items that relate to the number of customers. These costs are fixed and occur even when no electricity is used. The costs related to meters, customer accounting, customer sales, and customer service and information are classified as Customer-related costs.

Distribution plant below Distribution Bulk Delivery voltages of 46 kV, 34 kV, and 23 kV are classified as both Customer-related and Demand-related. Distribution Primary,

Distribution Secondary, Distribution Transformers, and Distribution Services are classified into Demand and Customer components based on the results of a Distribution Plant Study on Minnesota Power's system, which was conducted with 2025 data. As further described in MP Exhibit ___ (Levi Peterson), Direct Schedule 1 attached to my Direct Testimony, the study was based on page 87 of the NARUC Cost Allocation Manual's minimum-system methodology, where the minimum system is classified as Customer-related and the remaining portion is classified as Demand-related (Chapter 6, page 87). The results are summarized below in Table 5, and the Distribution Plant Study is included in Volume 4, Workpapers, OS-1.

Table 5. Classification of Distribution Plant

Based on 2025 Distribution Plant Study

Plant	FERC Account *Function Code*	Function	Customer Classification Minimum System %	Demand Classification %
Poles , Towers	364, 365	Primary Overhead Lines	42.91%	57.09%
OH Conductors	*D300*	Secondary Overhead Lines	37.84%	62.16%
UG Conduits, &	366, 367	Primary Underground Lines	30.39%	69.61%
Conductors	*D400*	Secondary Underground Lines	8.91%	91.09%
Line	368	Overhead Transformers	48.96%	51.04%
Transformers	*D500*	Underground Transformers	67.33%	32.67%
Services	3691	Overhead Services	88.88%	11.12%
	3692	Underground Services	35.06%	64.94%
	D600			

Q. Please describe the allocation of each of these classifications.

A. Once all items are assigned to a classification, the costs are treated as bases for Demand, Energy, and Customer classification allocators. The classification allocators are calculated in the model and used to allocate the respective costs to each classification. The names of the classification allocators for each rate base and income statement reporting line components are set forth in Table 5 of the "Guide to Minnesota Power's CCOSS" attached to my Direct Testimony as MP Exhibit ___ (Levi Peterson), Direct Schedule 1. The classification allocators for rate base line items are also shown in

Volume 3, Direct Schedule E-3, Part 5a. The classification allocators for operating income line items are shown in Volume 3, Direct Schedule E-3, Parts 5b and 5c. The classification allocator bases are shown in Volume 3, Direct Schedule E-3, Part 6a, and the classification allocator factors are shown in Volume 3, Direct Schedule E-3, Part 6b.

Q. Please describe the last step of separating the costs between jurisdictions.

A. The last step is to allocate the costs between Minnesota Power's FERC and Minnesota jurisdictions. The separation of costs between jurisdictions in the present filing follows the same procedures that were used in Minnesota Power's last five completed retail rate cases before the Commission (Docket Nos. E015/GR-08-415, E015/GR-09-1151, E015/GR-16-664, E015/GR-21-335, and E015/GR-23-155) and the Company's last FERC wholesale rate case (FERC Docket No. ER08-397-000).

Q. What is the basis used for the jurisdictional separation of Production-Demand and Transmission costs?

A Both Production-Demand and Transmission costs are allocated based on the 12CP method. Under the 12CP method, these costs were apportioned between FERC and Minnesota jurisdictions based on the relationship between the total of all class firm loads in each jurisdiction at the time of Minnesota Power's 12 monthly system peaks.

Q. What is the basis used for the jurisdictional separation of Distribution Bulk Delivery costs?

A Distribution Bulk Delivery facilities are allocated on the maximum annual class non-coincident peak demand ("Class NCP") method. These facilities are used to deliver power on a localized basis to the distribution system for both FERC wholesale customers and Minnesota retail customers. Therefore, these facilities are functionalized and kept distinct from transmission facilities. Because of the localized nature of the loads served off the distribution bulk delivery system, their diversity is less than that on the transmission system. Annual maximum non-coincident peak demands reflect the customer loads that are considered in designing the distribution system, and therefore these same peak demands are used for jurisdictional separation purposes. The separation

is accomplished by aggregating the non-coincident peak demands of all FERC jurisdictional customers served from distribution bulk delivery points and separately aggregating such peak demands for all Minnesota retail customers. As a result, the Minnesota jurisdictional responsibility is the retail aggregated demands divided by the total of the FERC and retail aggregated non-coincident peak demands.

Q. Would you explain the basis for the jurisdictional separation factor relative to energy responsibility?

A. The energy responsibility factors are based on Minnesota and FERC jurisdictional energy sales kilowatt-hour ("kWh"), excluding Large Power Replacement Firm Power Service ("RFPS") energy and Silver Bay Power Fixed and Variable Priced energy—all of which are adjusted for losses to the production level.

Q. How are the jurisdictional separation factors for customer costs developed?

A. There are three jurisdictional separation factors for customer costs—Meters, Customer Accounting, and Customer Service and Information. The Meter allocation factor is based on the total meter plant balance. The meter costs are first allocated by identifying (i) the meter original investment cost ("OIC") for each wholesale customer and (ii) the OIC for Large Power customers. These identified amounts from specific plant records are subtracted from the total meter costs. An average OIC is then calculated using the number of meters in each of the remaining rate classes and the meter costs in the specific plant records. The remaining meter costs (*i.e.*, miscellaneous cost) are subsequently distributed to the jurisdictions using ratios developed by Minnesota Power's meter department based on the quantity of miscellaneous small equipment identified in each rate class and its associated costs.

For 2025, the jurisdictional separation of costs assigned to Customer Accounting and Customer Service and Information is based on actual historic dollar amounts and the number of hours worked by employees. The number of hours are allocated according to the amount of time spent among the two jurisdictions by rate classes, and these ratios are then applied to the dollar amounts.

Q. Did the 2026 projected year and the 2027 test year use the same actual allocation ratios as 2025 for customer costs?

A. Yes. The 2026 projected year and the 2027 test year budgeted amounts were allocated using the 2025 ratios to determine 2026 and 2027 allocation factors. The jurisdictional separation of customer costs in the present filing follows the same procedures approved or affirmed by the Commission in Minnesota Power's last five completed retail rate cases (Docket Nos. E015/GR-08-415, E015/GR-09-1151, E015/GR-16-664, E015/GR-21-335, and E015/GR-23-155) and the Company's last FERC wholesale rate case (FERC Docket No. ER08-397-000).

Q. How do the allocation factors described above for jurisdictional separation compare to those used in the 2023 Rate Case?

A. The comparison of the jurisdictional allocation factors is shown in MP Exhibit ___ (Levi Peterson), Direct Schedule 2 attached to my testimony. As discussed above, the jurisdictional allocation methods are the same as used in the Company's last five completed retail rate cases.

The test year jurisdictional allocation factor ratios used in Minnesota Power's CCOSS can be found in Volume 3, Schedules B-16 to B-19 and Schedules C-13 to C-16, as follows:

- Schedule B-16 lists the rate base components by CCOSS reporting line and provides the jurisdictional allocator names/codes for each reporting line;
- Schedule B-17 provides the Total Company jurisdictional allocator bases by classification for the Unadjusted Most Recent Fiscal Year 2025, Unadjusted Projected Fiscal Year 2026, and Proposed Test Year 2027;
- Schedule B-18 provides the Minnesota Jurisdiction allocator bases by classification for the Unadjusted Most Recent Fiscal Year 2025, Unadjusted Projected Fiscal Year 2026, and Proposed Test Year 2027;

- Schedule B-19 provides the Minnesota Jurisdiction allocator factors by classification for the Unadjusted Most Recent Fiscal Year 2025, Unadjusted Projected Fiscal Year 2026, and Proposed Test Year 2027;
- Schedule C-13 lists the Operating Income components by CCOSS reporting line and provides the jurisdictional allocator names/codes for each reporting line; and
- Schedules C-14, C-15, and C-16 reference back to Volume 3, Schedules B-17, B-18, and B-19 to the Total Company jurisdictional allocator bases, Minnesota Jurisdiction allocator bases, and Minnesota Jurisdiction allocator factors, respectively.

The development of the allocation factors is detailed in Volume 4, Workpapers, under Allocation Factors ("AF"). In addition to those allocation factors, which are referred to as "externally developed," there are also a number of "internally developed" allocation factors that are generated by the CCOSS model. These allocation factors are generated based on one or more revenue, expense, or rate base items that have been allocated to jurisdiction and customer class within the CCOSS model using one or more of the "externally developed" allocators. Additional details regarding the "internally developed" allocation factors are set forth in the "Guide to Minnesota Power's CCOSS" attached to my Direct Testimony as MP Exhibit ___ (Levi Peterson), Direct Schedule 1.

Q. Do you have any comments on the comparison of the jurisdictional allocation factors?

A. Yes. Comparing the three-year period of 2025, 2026, and 2027, the jurisdictional allocation of costs shifts away from the retail jurisdiction. The primary drivers are listed below; please refer to the Direct Testimony of Company witness Arik C. Forsman for more information.

1. Energy consumption in the paper production industry continues to decline, as seen in a decrease in load from Boise, UPM-Blandin, and Verso Duluth. Sofidel's (formerly ST Paper) increase in usage has not offset the overall downward trend.

2. There is a considerable decline in energy consumption from the retail mining and metals industry.
3. Mesabi Metallics' expected operation has caused an increase in the non-retail jurisdiction, because the facility will be served through Nashwauk, a wholesale customer.

The combination of declining retail load in 2027 along with the increase of non-retail load has resulted in a shift of the jurisdictional allocators away from the retail customer classes. This can be seen most significantly in Power Supply Production, Power Supply Transmission, and Distribution Bulk Delivery. Please refer to MP Exhibit ___ (Levi Peterson), Direct Schedule 2 for more detailed information.

V. ALLOCATION OF COSTS TO RETAIL CLASSES

Q. Please describe the basis on which allocation of costs was made among the retail classes of customers.

A. Three basic types of allocation factors are required to allocate the costs of serving retail customers. These are based on the demand (instantaneous power or load, which can be measured in kilowatts ("kW")) placed on the system by the customers, the energy (quantity or amount of electricity, which is commonly measured in kWh) supplied to the customers, and the number of customers being served. Each of these factors is developed for application to the related classified costs. The test year jurisdictional and customer class allocation factor ratios used for General Rates can be found in Volume 3, Schedule E-3, Class Cost of Service Study – Proposed Test Year. Details on the development of allocation factors are set forth in the "Guide to Minnesota Power's CCOSS" attached to my Direct Testimony as MP Exhibit ___ (Levi Peterson), Direct Schedule 1. The calculations of the allocation factor values are detailed in Volume 4, Workpapers, AF.

Q. Were the retail class allocation factors developed using the same methodologies as in Minnesota Power's last rate case?

A. Yes, apart from the modification to the methodology for meter cost classification discussed above, the CCOSS in the present filing uses the same classification and cost allocation methodologies. Fixed production costs are classified as 100 percent demand and allocated to class on the 4CP Average and Excess method. Transmission costs are classified as 100 percent demand and allocated to class on the 12CP method. Distribution costs are classified and allocated following the Minimum System method, and energy costs are allocated on the E8760 allocators. Refer to MP Exhibit ___ (Levi Peterson), Direct Schedule 1, for further details on these methods.

Q. What analyses were used to produce inputs to the CCOSS in this rate case?

A. Below is a list and brief description of analyses used to produce inputs to the CCOSS.

(a) Demand allocation factors analyses — Analyses of demands were carried out by jurisdiction, by customer class, and in some cases, by customer. The analyses were based on the most recently available historical load data from 2025, as well as from the projected year and test year budgeted demands. Actual hourly data was used to scale the budgeted 2026 and 2027 loads. Therefore, the Company will be utilizing the most recent available actual data to scale budgeted data, as opposed to relying on older load research results. Refer to MP Exhibit ___ (Levi Peterson), Direct Schedule 1, and to Volume 4, Workpapers, AF for further details.

(b) Energy allocation factors analyses — Analyses of energy usage were carried out by jurisdiction, by customer class, and in some cases, by customer. Similar to the demand allocation factors analyses, the energy analyses were based on the most recently available historical load data from 2025, as well as from the projected year and test year budgeted demands. Actual hourly data was used to scale the budgeted 2026 and 2027 loads. In the past, Minnesota Power has utilized the E8760 energy allocator to allocate

energy costs to customer classes[7] using annual hourly load shapes from previous load research. The scaling is now based on the most recent actual hourly load shapes. Refer to MP Exhibit ___ (Levi Peterson), Direct Schedule 1, and to Volume 4, Workpapers, AF for further details.

(c) Customer allocation factors analyses — Analyses of the number of customers using facilities, plant balances by class, and labor expenses and hours were carried out in developing the customer allocation factors. The analyses were based on the most recently available historical data from 2025, budgeted data for 2026, as well as from 2027 test year projected numbers of customers. Refer to MP Exhibit ___ (Levi Peterson), Direct Schedule 1, and to Volume 4, Workpapers, AF for further details.

(d) Distribution Plant Study, including minimum system — Results from the Distribution Plant Study were utilized to sub-functionalize and classify distribution plant into both Demand- and Customer-related components. The Distribution Plant Study was updated since Minnesota Power's last rate case and is now based on analyses from the 2025 data and field conditions. The report is included in Volume 4, Workpapers, OS-1.

(e) Lead-Lag Study — Revenue lead days and expense lag days utilized in estimating test year cash working capital were updated since the Company's last rate case. The Lead-Lag Study was updated based on 2023 data. The report is included in Volume 4, Workpapers, OS-2.

Q. What do you conclude regarding the Company's allocation of costs in this proceeding among retail customer classes?

A. The Company is using long-established practices to allocate costs among customer classes, which results in reasonable overall cost allocations. As discussed above, the

[7] This history and development of the E8760 allocator is discussed in the "Guide to Minnesota Power's CCOSS," attached as MP Exhibit ___ (Levi Peterson), Direct Schedule 1, at page 13.

final revenue requirements based on this cost allocation provide direction to the Commission to develop a reasonable alignment between cost causation and rates.

VI. COST RECOVERY RIDERS

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I identify Minnesota Power's cost recovery riders and discuss our approach to moving costs for completed projects from riders into base rates, where applicable. I also discuss a proposed alternative cost recovery mechanism for dewatering costs.

Q. Please summarize the different cost recovery riders Minnesota Power currently uses.

A. Minnesota Power is currently using the following major capital and energy cost recovery riders:

- Transmission Cost Recovery ("TCR") Rider;
- Renewable Resources Rider ("RRR");
- Solar Renewable Resources Rider ("SRRR"); and
- Fuel and Purchased Energy Rider ("FPE") Charge

The Company uses numerous other riders as listed in the Company's rate book, some of which are addressed by Company witness Leah Peterson.

Q. Are there any Order Points from the rate case filed by the Company in 2016 (Docket No. E015/GR-16-664) (the "2016 Rate Case") that apply to your discussion of riders in this proceeding?

A. Yes. In Order Point 47 in the Commission's 2016 Rate Case Order, the Commission required that:

> In future rate cases, cost recovery for facilities shall be rolled in at the beginning of the rate case, and then no longer be recovered in riders, or facilities and rider collections shall be rolled into the rate

case at the end of the rate case if Minnesota Power wants to continue rider recovery.[8]

Q. Has Minnesota Power complied with Order Point 47 from the Commission's Order in the 2016 Rate Case by moving cost recovery from riders into base rates for completed projects?

A. Yes. To comply with Order Point 47, at the beginning of this rate case, Minnesota Power is moving into base rates the costs for projects that are/will be completed by December 31, 2026. The costs for projects that are currently being recovered through riders that will not be completed by December 31, 2026 will continue to be recovered through those riders, and Minnesota Power is excluding the costs of these projects from its request in this rate case.

Q. Can you provide a summary of the Company's proposed rider treatment in this rate case?

A. Yes. Table 6 below summarizes the projects and costs that will remain in each of the riders and the projects and costs that will be incorporated into base rates. These are discussed in more detail below.

[8] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 112 at Order Point 47 (March 12, 2018) (eDocket No. 20183-140963-01).

Table 6. Summary of Rider Treatment in 2027 Test Year

Transmission Cost Recovery Rider (TCR)	
Moving to Base Rates	**Staying in the Rider**
Duluth Loop Reliability Project	Regional Expansion Criteria and Benefits ("RECB") Net Expense/Revenue and Credit for MISO Multi-Value Project ("MVP") Revenue
Renewable Resources Rider (RRR)	
Moving to Base Rates	**Staying in the Rider**
Reset Production Tax Credit to 2027 budgeted level	Production Tax Credit True-up
	Longspur Wind
	Boswell Solar and Interconnection
	Regal Solar and Interconnection
Solar Renewable Resources Rider (SRRR)	
Moving to Base Rates	**Staying in the Rider**
None	Camp Ripley
	Community Solar Garden
	SolarSense Program

Q. In general, does moving costs from riders into base rates increase the amount that is billed to customers?

A. No, because the customer is already paying for those costs in the rider in a separate line in their bill. This simply moves the recovery to base rates.

Q. Why does Minnesota Power propose to roll the Duluth Loop Reliability Project costs into base rates?

A. The Duluth Loop Reliability Project has an in-service date of December 31, 2026. As such, it is appropriate to remove it from the TCR and include the used and useful project in base rates. The Duluth Loop Reliability Project has a test year revenue requirement impact of $9.2 million (MN Jurisdiction).

Q. Are there any residual capital costs for the Duluth Loop Reliability Project past December 31, 2026?

A. Yes. There are $1,275,169 of capital costs planned in September of 2027 due to a land transfer as shown in Schedule B-11 (IR), page 2. The Company is also including these costs with the Duluth Loop Reliability Project and rolling them into base rates.

Q. Why does Minnesota Power not propose to include Longspur Wind, Boswell Solar, and Regal Solar in base rates?

A. Longspur Wind, Boswell Solar, and Regal Solar have planned in-service dates after the start of the 2027 test year. Because of this, they will not be used and useful for the duration of the test year and should not be included in base rates.

Q. Why does the Company propose to continue to recover MISO costs and revenues in the TCR?

A. The MISO transmission facility net revenues and expenses relate to the costs of MISO Transmission Expansion Planning projects, those which have not been directly assigned to the FERC jurisdiction, and MISO Auction Revenue Rights revenues for the MVPs of which Minnesota Power is not an owner but for which Minnesota Power is allocated a portion of the costs and revenues as a MISO member. As these expenses and revenues vary from year to year, Minnesota Power provides the net credit in the TCR rather than in base rates, as a longstanding practice approved by the Commission.

Q. What revenues and expenses does Minnesota Power propose to continue to recover in the RRR?

A. Minnesota Power proposes to include, as required by Order Point 37 from the Commission's Order in the Company's 2016 Rate Case, an annual true-up of actual PTCs generated by the Company's facilities. Beginning with Interim Rates, the PTC amount in base rates will be reset from the level established in the Company's last rate case to the 2027 test year budgeted amount, and the new level will be used going forward as a baseline with the true-up calculation in the RRR.

Q. Briefly describe the impact of resetting PTCs in base rates.

A. Resetting PTCs from the level established in base rates in the Company's last rate case to the updated 2027 budgeted PTCs increases the base rate revenue requirements by about $23.0 million MN Jurisdictional. This represents approximately 15.4 percent[9] of the Company's Interim Rate revenue requirement increase and about 13.8 percent[10] of the Company's requested General Rate revenue requirement increase. Beginning with Interim Rates, the new base rate PTC level will be reset going forward in the true-up calculations in the RRR. Assuming actual PTCs come in at the budgeted level, this means the monthly true-up in the RRR will be zero.

Q. Why is there a decrease in 2027 test year PTCs compared to the Company's last approved rate case?

A. As stated in the Company's 2027 Renewable Resources Rider and 2027 Renewable Factor (Docket No. E015/M-26-331), the Company is no longer receiving PTCs from the Bison Wind Energy Center ("Bison Wind") which has caused a substantial loss of generated tax credits.

Q. Please summarize the impact on Interim and Final Rate increases net of the rider changes described above.

A. Please refer to Schedule B-11 (IR) for a summary of the Interim and Final Rate increases net of riders. As shown in Schedule B-11 (IR), offsets in the TCR and RRR result in an Interim Rate net bill impact of about 15.5 percent. Similarly, offsets in the TCR and RRR result in a Final Rate net bill impact of about 17.8 percent. Schedule B-11 (IR), page 3 shows the estimated base rate revenue requirement impact resulting from resetting the PTC level established in base rates in the Company's last rate case to the updated 2027 budgeted PTC level in this case.

[9] ($23.0 million / $148.9 million) = 15.4 percent.
[10] ($23.0 million / $166.6 million) = 13.8 percent.

Q. What does Minnesota Power propose with respect to the SRRR?

A. In the April 20, 2021 Order in the Company's 2020 Solar Renewable Factor (Docket E015/M-20-557), the Commission approved the implementation of billing factors to recover the costs related to Minnesota Power's Camp Ripley Solar project, Community Solar Garden projects, and SolarSense Program.[11] The Solar Renewable Factor was approved to appropriately allocate and recover costs to customers as set out in Minnesota's Solar Energy Standard ("SES").[12] The SES includes a provision that exempts certain customers from paying costs to meet the SES. Because of this, all solar-related revenues and costs are excluded from the 2027 test year. Furthermore, due to the complexity created by exemptions from the SES, Minnesota Power envisions that future solar costs needed to meet the SES will continue to be excluded from future rate cases.

Q. Has the 2027 test year been adjusted to account for the rider treatment discussed above?

A. Yes, Minnesota Power has made the appropriate adjustments to ensure that all rate base items, expenses, and revenues related to items staying in riders have been removed from the 2027 test year. These adjustments are discussed by Company witness Turner and are shown in Volume 3, Direct Schedule B-6 and Direct Schedule C-10 for Total Company and in Volume 3, Direct Schedule B-5 and Direct Schedule C-9 for MN Jurisdictional. Details are also shown in Volume 4, Workpapers, ADJ-RB-13 and ADJ-IS-26.

Q. Please describe the types of costs the Company is incurring related to the Coal Combustion Residuals ("CCR") Rule and Legacy Rule.

A. As described in the Direct Testimony of Company witness Todd Z. Simmons, the Company is incurring various environmental compliance costs related to the CCR Legacy Rule and the 2015 CCR Rule (also called the 2015 Rule in the Direct Testimony of Company witness Simmons).

[11] *In the Matter of the Petition by Minn. Power for Approval of its 2020 Solar Renewable Factor within its Renewable Resources Rider*, Docket No. E015/M-20-557, ORDER (April 20, 2021) (eDocket No. 20214-173148-01).

[12] Minn. Stat. § 216B.1691, subd. 2f (2025).

Company witness Simmons describes the CCR Legacy Rule. In an order dated October 29, 2025, in Docket No. E015/M-24-437, the Commission approved Minnesota Power's request to track and defer its costs resulting from the CCR Legacy Rule.

To meet requirements of the 2015 Rule, the Company expects to incur additional costs, although the total scope for all requirements is not currently known. In particular, as described by Company witness Simmons, the 2015 Rule included requirements for groundwater monitoring and corrective action at existing CCR impoundments at Boswell. In the Company's most recent decommissioning study, completed in December 2025, significant costs were included for the first time to meet the dewatering requirement. While these costs are part of the 2015 Rule, they are new to the Company and were first included in the calculation for decommissioning in 2026.

Q. How does the Company propose to recover costs associated with these two categories of CCR-related costs?

A. For CCR Legacy Rule costs, the Company is required to track any costs, along with any related revenues, credits, or offsets, and provide an update on cost estimates with the Commission in Docket No. E015/M-24-437. Updated information about the status of the CCR Legacy Rule is also discussed in the Company's most recent remaining life petition in Docket No. E015/D-26-327. The Company proposes to continue deferring these costs until there is more certainty around pending litigation and potential scaling of the requirements of the rule.

The Company has included other changes in decommissioning expenses in the 2027 test year, which is consistent with prior cost recovery for non-CCR Legacy rule costs. However, because much of these costs are driven by evolving information due to potential responses to dewatering costs, the Company is open to an alternative cost recovery mechanism as discussed below.

Q. Please describe the alternative cost recovery mechanism you are proposing for incremental decommissioning costs for the Boswell Energy Center, Laskin Energy Center, and Hibbard Renewable Energy Center driven by the 2015 Rule?

A. While there is certainty that Minnesota Power will need to meet the 2015 Rule requirements that are not being challenged with litigation, the Company acknowledges uncertainty around which technology and proposed solution will ultimately be permitted to meet the updated compliance requirements. Because of this uncertainty, the Commission may prefer to move these incremental decommissioning costs out of base rates and into a separate tracker.

The Company supports establishing a tracker and true-up mechanism where costs associated with incremental decommissioning costs could be charged to customers through a bill surcharge or similar mechanism, and costs could be tracked and updated on an annual basis separate from base rates and the rate case process. The Company is also open to a tracker limited to dewatering costs, which represent approximately half of the $13.09 million Total Company incremental costs and are most subject to change as technologies evolve (as Company witness Simmons discusses).

Q. Why is a tracker mechanism for these costs reasonable?

A. While the Company has updated its decommissioning expense in the test year based on the most recent cost and project information included in its December 2025 decommissioning study, Company witness Simmons explains that there is uncertainty around the specific technology that will be utilized to meet dewatering requirements in particular. A tracker mechanism is reasonable because it will allow cost recovery to be updated as additional actual information becomes available regarding the scope, timing, and cost of these incremental decommissioning costs. A tracker will allow the Commission to adjust the incremental anticipated decommissioning costs for each given year, starting with 2028, when there is updated information between rate cases. If Minnesota Power identifies lower cost technologies or more efficient approaches to completing decommissioning activities, those benefits to customers can be reflected in the tracker mechanism. And given that the primary driver of these costs is closure of the

Boswell Energy Center Units 3 and 4 within the next decade, a tracker will avoid over- or under-recovery to the extent these costs update over time. This will also ensure that customers who are currently relying on BEC Units 3 and 4 to provide power are paying a reasonable share of decommissioning costs over the units' remaining lives.

Q. Why does the Company not propose to utilize deferred accounting for these costs?

A. Minnesota Power considered requesting deferred accounting for these incremental costs. However, CCR compliance costs are incorporated into depreciation and recovered over the entire life of the asset. When decommissioning requirements change with little remaining life left for plants, the result is elevated depreciation. Given that the assets in question are nearing the end of life, the Company is concerned that delaying cost recovery now will build up costs for a more substantial recovery amount over a shorter period at a later date.

Additionally, dewatering costs are different from the CCR Legacy Rule costs currently being deferred because there is certainty these remediation projects will be required. In contrast, the CCR Legacy Rule is being challenged and could be significantly altered or even eliminated. Therefore, the issue is the uncertainty in cost amounts, not whether the work will be required at all.

VII. CONCLUSION

Q. Does this complete your testimony?

A. Yes.

Guide to Minnesota Power's Class Cost of Service Study (CCOSS)

Functionalization, Classification, and Allocation of Rate Base and Income Statement

Guide to Minnesota Power's CCOSS
Functionalization, Classification, and Allocation of Rate Base and Income Statement

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I. INTRODUCTION

This guide discusses the functionalization, classification, and allocation methodologies used by Minnesota Power (or the "Company") in the Class Cost of Service Study ("CCOSS") process. The guide provides the following information:

- A description, explanation, and justification of the functionalization, classification, and allocation of each rate base and income statement cost in the CCOSS in the order that they are shown in the CCOSS.

- A description of both externally- and internally-developed allocation factors.

- A summary table (Table 5) providing the functionalization, classification, and allocation of each rate base and income statement cost. The table lists each CCOSS line item cost as it is functionalized and indicates the related Federal Energy Regulatory Commission ("FERC") account, plant account, or Minnesota Power function code. Table 5 shows how the item is classified, how it is allocated to jurisdiction and class, whether it is allocated with an internal or external allocator, and the name of the allocator.

Throughout this guide, related work papers, studies, and other inputs are referenced as appropriate to provide the location of those items in the rate filing.

All functionalization, classification, and allocation methodologies presented in this guide are the same as the Minnesota Public Utilities Commission ("MPUC" or "Commission") affirmed in Minnesota Power's last rate case, Docket No. E015/GR-23-155 ("2023 Rate Case") with the exception of meter classification as mentioned in the Direct Testimony of Company witness Levi A. Peterson.

FERC Order No. 898 is an accounting order related to minor changes and further specifications of FERC accounts. This does not change Minnesota Power's CCOSS methodology. A complete list of the additions and specifications is shown in Table 1 – Attachment 1.

This guide is intended to help ensure transparency in Minnesota Power's CCOSS process and documentation.

II. ALLOCATION FACTORS

There are two basic types of allocators used in the CCOSS: externally-developed allocators that are developed using data external to the CCOSS model, and internally-developed allocators that are automatically calculated based on data internal to the CCOSS model.

A. External Allocation Factors

There are three types of external allocation factors: demand, energy, and customer. The externally-developed allocation factors listed in the Table of Contents are described below and are detailed in Volume 4, Workpapers, under Allocation Factors.

With the implementation of UIPlanner ("UIP"), the Company changed the allocator codes to be more intuitive and streamlined. The classification allocator codes are indicated by the "C" prefix. The classification allocators for rate base line items are shown in Volume 3, Direct Schedule E-3, Part 5a. The classification allocators for operating income line items are shown in Volume 3, Direct Schedule E-3, Parts 5b and 5c. The classification allocator bases are shown in Volume 3, Direct Schedule E-3, Part 6a, and the classification allocator factors are shown in Volume 3, Direct Schedule E-3, Part 6b.

The customer class allocator codes are indicated by the "CC" prefix. The customer allocators for rate base line items are shown in Volume 3, Direct Schedule E-3, Part 7a. The customer class allocators for operating income line items are shown in Volume 3, Direct Schedule E-3, Parts 7b and 7c. The customer class allocator bases by classification are shown in Volume 3, Direct Schedule E-3, Part 8a, and the customer class allocation factors by classification allocator factors are shown in Volume 3, Direct Schedule E-3, Part 8b.

As can been seen in the customer class allocators, the FERC jurisdiction is considered a class, and therefore, no separate coding or naming is required for the FERC jurisdiction.

B. Internal Allocation Factors

Internally-developed allocators are ratios based on one or more revenue, expense, or rate base items that have been allocated to classification, jurisdiction, and class within the CCOSS using one or more other allocators. The internally-developed allocator codes, bases, and customer allocation factors are also shown together with the external allocators described and identified above.

The externally-developed and internally-developed allocators are also identified in Table 5.

III. RATE BASE

A. Summary of Approaches and Assumptions

Minnesota Power develops rate base using an average method. All rate base items, except working capital, were developed by averaging beginning and ending year balances. A 13-month average balance is used in the calculation of working capital. Refer to Volume 3, Direct Schedule B-7, Summary of Approaches and Assumptions Used in Determining Average Rate Base for the Projected Fiscal Year and Proposed Test Year.

B. Steam Plant: FERC Accounts 310-317

Steam Plant is assigned to the Production function and is classified as 100 percent demand.

This assignment is consistent with Minnesota Power's last five retail rate cases (Docket Nos. E015/GR-08-415, E015/GR-09-1151, E015/GR-16-664, E015/GR-21-355, and E015/GR-23-155) and was affirmed by the Commission in the Company's 2023 Rate Case. It is also consistent with the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Manual") classification of Steam Production Plant to 100 percent

demand if no direct assignment or exclusive use cost is assigned directly to customers (Chapter 4, page 35).

Production – Demand is allocated between Minnesota Power's FERC and MPUC jurisdictional classes based on the 12-month average coincident peak ("12CP") method where costs are apportioned based on the relationship between the total of all class loads in each jurisdiction at the time of Minnesota Power's 12 monthly system peaks. This method is appropriate since Minnesota Power's system historically reflects little seasonality or significant deviations in monthly peaks.

This method was used and was approved or considered in Minnesota Power's last five retail rate cases as well as our last FERC wholesale rate case. This method is also one of the methods suggested by the NARUC Manual (Chapter 4, page 46).

The Production – Demand function is allocated to retail class using the Four Coincident Peak Average and Excess methodology ("4CP A&E") as described below.

The 4CP A&E methodology allocates fixed production costs to class based on a composite allocation factor that is composed of two parts – 1) an average demand and 2) an average of the four highest coincidental peaks less the average demand. Similar to the traditional Average and Excess method and other energy weighting methods, all plant costs may remain classified as demand-related. NARUC Manual (Chapter 4, page 49) characterizes these methods as "partial energy weighing methods."

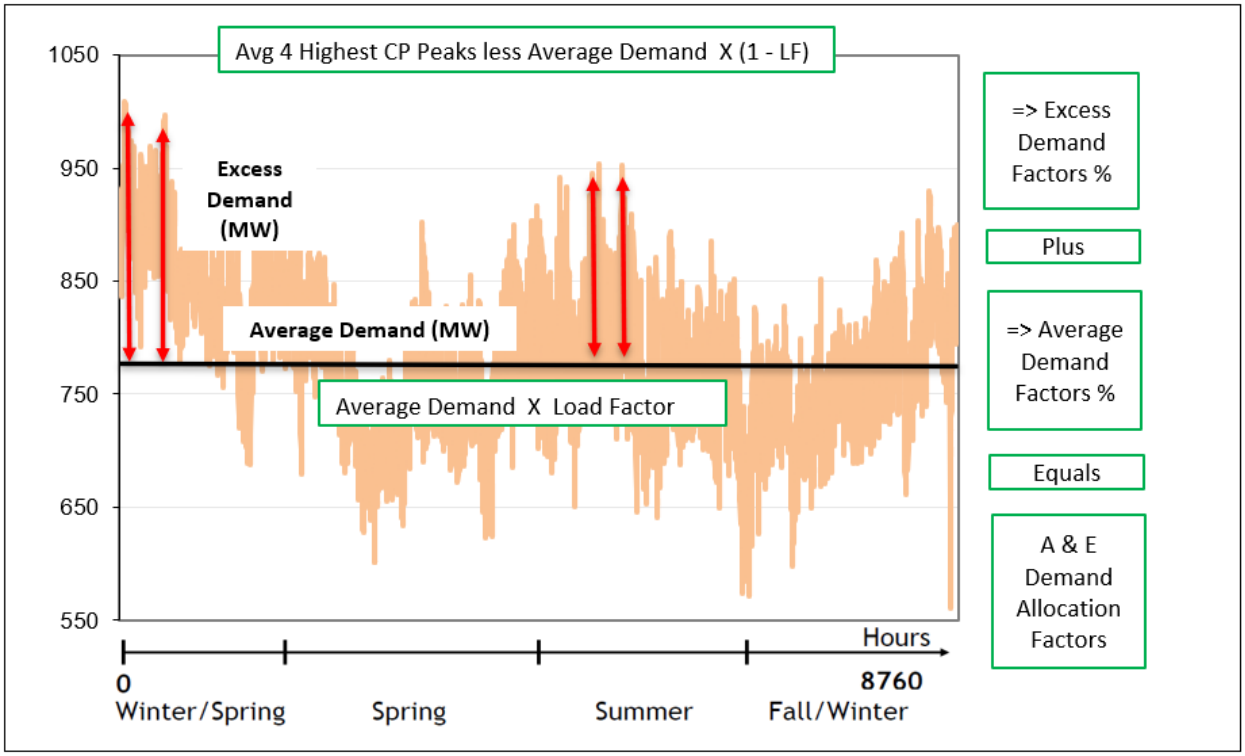
The initial step is accomplished by the 4CP A&E method in the first part of the composite allocator – the average demand part. Each class's proportion of total average demand (or energy) is multiplied by the system load factor (LF) to yield that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. Load factor is defined as total average demand divided by total coincident peak. The second part of the 4CP A&E allocator allocates the balance of the costs on each class's contribution to the Company's system peaks that are in excess of their average demand. The composite allocator can be shown as follows:

$$\text{Composite Allocation Factor} = (1 - LF) \times (\text{Excess Demand Factor}) + LF \times (\text{Average Demand Factor})$$

Where the Excess Demand Factor is the average of the four highest coincident peaks less the average demand.

The methodology is illustrated in the figure below.

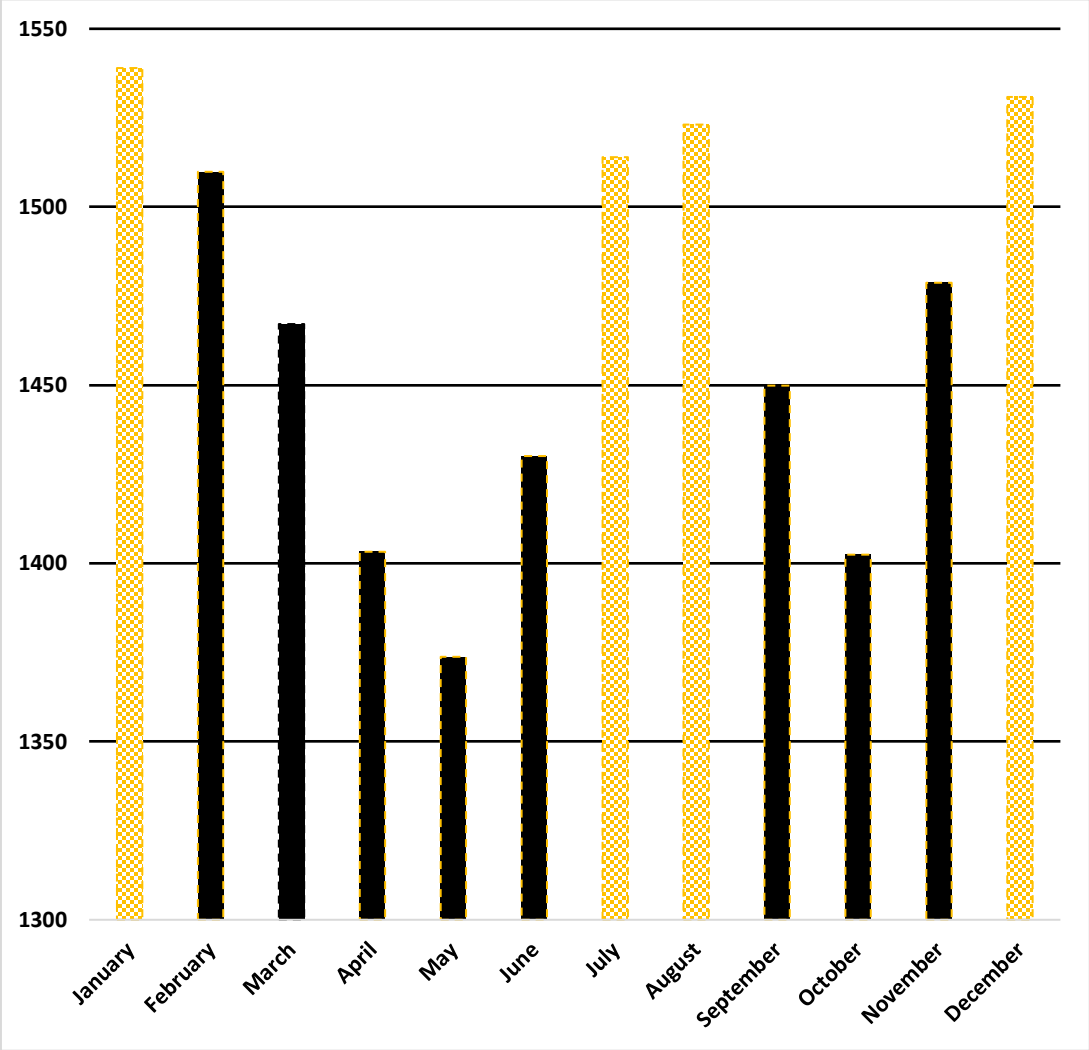
Figure 1: 4CP A&E Methodology



As illustrated in Figure 1 above, the methodology allocates costs in proportion to each class's contribution to the Company's system peaks that are in excess of their average demand. Simultaneously, the method also allocates costs to each class based on the average demand they place on the system. Therefore, the method recognizes customers benefit from both demand and energy production from the Company's fixed generation assets and allocates costs accordingly.

The 4CP A&E method also captures the impact of each class on the Company's four highest peaks. The Company is unique in that it is a winter peaking utility with strong summer peaks and, therefore, must plan to meet the demand of those peaks accordingly. Historically, the average of the four highest peaks captures or accounts for almost 98 percent of the annual maximum peaks. The selection of each class's contribution to the Company's two winter peaks and two summer peaks in the allocation methodology, therefore, reflects cost causation. Figure 2 below shows Minnesota Power's historic average system peaks by month in yellow.

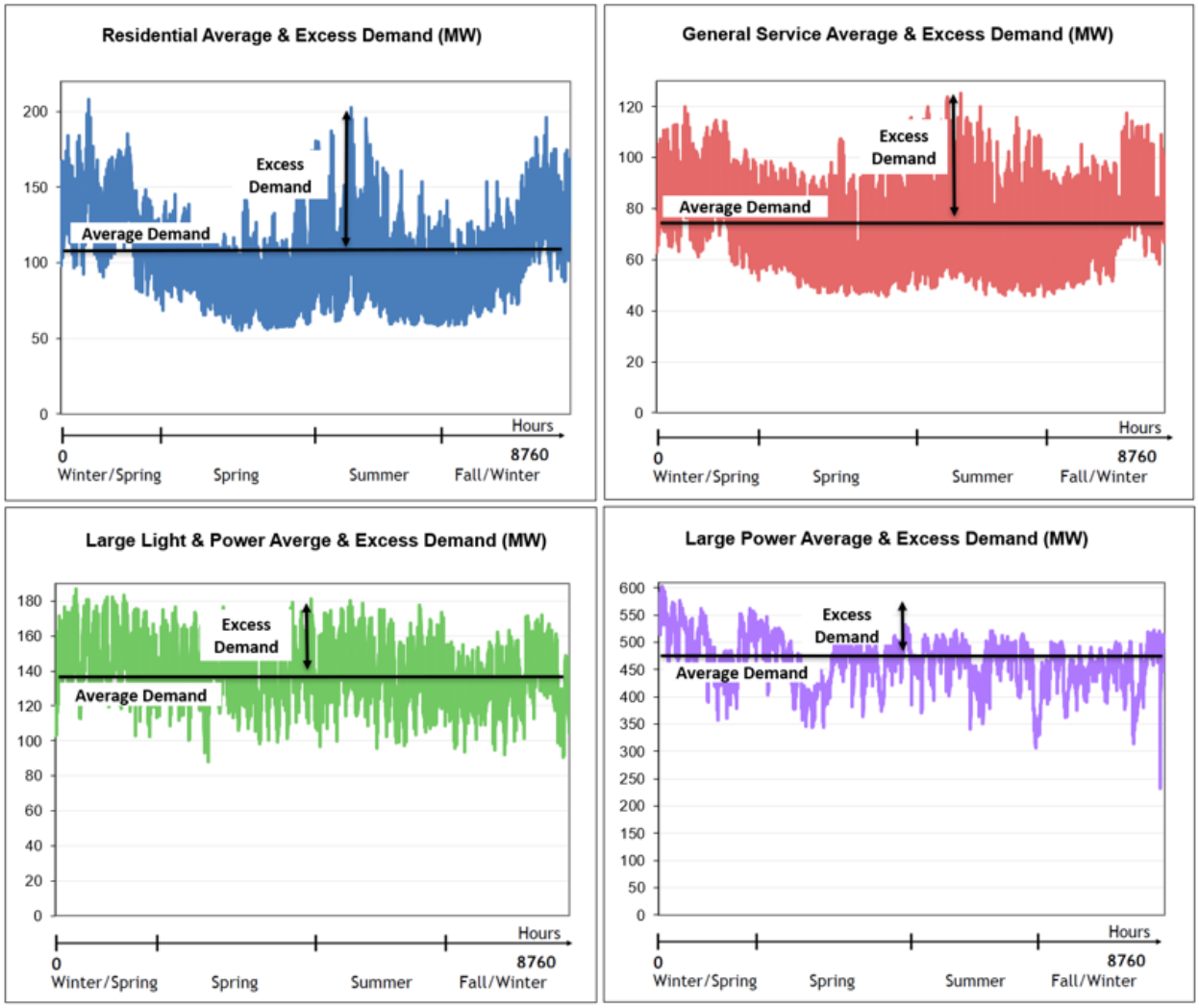
Figure 2: Minnesota Power's Historic Four Highest Average System Peaks 2010-2025 Megawatt ("MW")



As illustrated in the example below in Figure 3, each class has unique average and excess demand characteristics that impact the Company's systems and, therefore, create costs that are attributable to each class which should be allocated accordingly. The 4CP A&E method does just that and reflects cost causation by capturing each class's contribution to the system's four highest peaks and each class's contribution to the system average demand.

By capturing or accounting for each class's unique load characteristics, the 4CP A&E method provides cost signals needed for utility of the future initiatives. For example, accurate cost allocations are important when considering peak shifting or peak reduction programs which support lower overall system costs. This methodology aligns with the Company's Residential time of day, Large Light & Power time of use, and Large Power demand response initiatives while being supportive of Commission policy on rate design.

Figure 3: Illustration of A&E Demands by Class



The Commission has affirmed the Company's classification and allocation of fixed production costs using the 4CP A&E methodology in the Company's last two retail rate cases.

The development of the Production – Demand class allocators (CC-PROD) are detailed in Volume 4, Workpapers, under Allocation Factors.

C. Hydro Plant: FERC Accounts 330-336

Hydro Plant is assigned to Minnesota Power's Production function. All regulated hydro reservoir projects and assets at reservoir facilities are classified as energy and all remaining hydro plant is classified as demand.

This method is consistent with Minnesota Power's last five retail rate cases, Minnesota Power's last FERC wholesale rate case, and is also consistent with the NARUC Manual (Chapter 4, pages 35 and 38).

Hydro Production – Demand is allocated to customer class following the same methodologies as described above for the Production – Demand function.

Hydro Production – Energy is allocated between classes based on energy. The energy responsibility factors Production – Energy (CC-PROD) are based on MPUC and FERC jurisdictional kilowatt hour ("kWh") sales, excluding Large Power Replacement Firm Power Service ("RFPS") energy, adjusted for losses to the production level.

Excluding RFPS is consistent with Minnesota Power's most recent five retail rate cases as well as Minnesota Power's treatment of the revenues from RFPS as revenue credits which are distributed back to the Company's standard retail and wholesale classes of customers.

Hydro Production – Energy is allocated among Minnesota Power's retail customer classes using the Production – Energy (CC-PROD) or E8760 energy allocator.

Minnesota Power's E8760 energy allocator was initially developed and approved for use in Minnesota Power's Boswell 3 Emissions Reduction Plan Cost Allocation and Rate Design. This allocator was modeled after Xcel Energy's E8760 allocator and adapted for Minnesota Power's use. Minnesota Power's E8760 allocator was used in and approved by the MPUC in Minnesota Power's last four retail rate cases.

The E8760 allocator is an energy-cost allocator based on the time-of-use concept, which recognizes the importance of linking the time when a customer consumes electricity to the cost of providing electricity at that given time. A customer class that consumes proportionately more of its energy during periods of high or peak demand, when the market price for electricity is higher, should be expected to be charged more than a customer who consumes energy off peak.

The E8760 is based on Minnesota Power's system Locational Marginal Price ("LMP") hourly cost and the hourly energy use of each class. It is derived by multiplying the hourly energy usage of each class by the system's LMP cost by hour, summing, and taking the ratio of the sum of each class to the total. Applied as a cost allocator, the E8760 will yield class-specific responsibilities that take into account class use patterns and time-variant system costs. In contrast to a straight, non-weighted energy allocator, the E8760 results in a slight shift of class-specific responsibilities away from classes that use proportionately more of their energy during off-peak periods to classes that use proportionately more of their energy during more expensive on-peak periods.

The E8760 factors are based on MPUC jurisdictional retail class kWh sales, excluding RFPS energy and Economy energy, all of which are adjusted for losses to the production level. This method of recognizing non-firm customers and distributing the costs associated with these customers to all of the Company's standard retail and wholesale classes of customers is consistent with Minnesota Power's last four retail rate cases. This method is also consistent with Minnesota Power's treatment of revenues from these services as revenue credits, which also distributes the revenues from these services back to the Company's standard retail and wholesale classes of

customers. This method most appropriately reflects cost and is superior to other possible energy allocators.

The development of the Production – Energy allocators (CC-PROD/E8760) are detailed in Volume 4, Workpapers, under Allocation Factors.

D. Wind Plant: FERC Accounts 340-347 (Excluding Solar Accounts)

Wind Plant is assigned to Minnesota Power's Production function and is classified as demand.

Wind Production – Demand is allocated to customer classes following the same methodologies as described above for the Production – Demand function; that is, the 12CP method for jurisdictional allocation and the 4CP A&E method for retail class allocations.

This treatment of wind plant was approved in Minnesota Power's last five retail rate cases and is consistent with the method approved in Minnesota Power's Renewable Resources Rider.

E. Solar Plant: FERC Accounts 340.1/.6, 341.5, 342.5, 343.5, 344.5, 346.5, 347.5, 355.5

Solar Plant is assigned to Minnesota Power's Production function and is classified as demand.

Solar Production – Demand is allocated to jurisdiction and to customer classes following the same methodologies as described above for the Production – Demand function; that is, the 12CP method for jurisdictional allocation and the 4CP A&E method for retail class allocations.

As discussed in the Direct Testimony of Company witness Levi Peterson, all costs related to Solar are excluded from the Test Year CCOSS because those costs are being recovered in ongoing riders. This treatment is consistent with Minnesota Power's last three retail rate cases.

F. Transmission Plant: FERC Accounts 352-359.9

Transmission Plant is functionalized to Production – Demand and to Transmission.

Transmission Plant that is functionalized to Production – Demand consists of step-up transformers at generating stations booked in transmission plant. The remainder of transmission plant is functionalized to the Transmission function. This also includes small scale batteries when they are attached directly to the transmission system and built to serve the Transmission function.

Transmission Production – Demand is allocated to customer classes following the same methodology as described above for the Production – Demand function.

Costs functionalized to Transmission are allocated to jurisdiction and class based on the 12CP method. The 12CP method aligns with cost allocations to the Company's FERC Municipal customers and with how most of the Midcontinent Independent System Operator's ("MISO") transmission costs are incurred by the Company. This allocator has been approved and used for decades for Minnesota Power's jurisdictional allocation. This treatment is consistent with Minnesota Power's last two retail rate cases.

The development of the Transmission jurisdictional and class allocators (CC-TRAN) are detailed in Volume 4, Workpapers, under Allocation Factors.

G. Distribution Plant: FERC Accounts 360-373

Due to the complexity of the functionalization, classification, and allocation of Distribution Plant, the functionalization and classification will be described first before allocation.

Functionalization and Classification of Distribution Plant

Minnesota Power first assigns Distribution Plant by function, then by sub-function, and then classifies as appropriate. Table 2 below lists Minnesota Power's sub-function codes with their corresponding FERC accounts. It should be noted that for FERC accounts 360 to 367, each sub-function includes more than one FERC sub-account. Therefore the functionalization/classification will be described by sub-function.

Table 2. Minnesota Power's Distribution Plant Functions by FERC Account

	FERC Account												
Function Code & Description	360	361	362	364	365	366	367	368	369	370	371	372	373
D100 Dist – Subs Non Bulk Delivery	X	X	X										
D123 Dist – Subs 23kv Bulk Delivery	X	X	X										
D134 Dist – Subs 34kv Bulk Delivery	X	X	X										
D146 Dist – Subs 46kv Bulk Delivery	X	X	X										
D200 Dist – Generation		X	X										
D223 Dist – Bulk Delivery Lines 23k 1/													
D234 Dist – Bulk Delivery Lines 34k 1/													
D246 Dist – Bulk Delivery Lines 46k	X	X		X	X								
D300 Dist – Overhead Lines	X			X	X								
D400 Dist – Underground Lines						X	X						
D500 Dist – Line Transformers								X					
D600 Dist – Services									X				
D650 Dist – Meters										X			
D660 Dist – Cust Prem, EV Charger											X		
D675 Dist – Leased Property												X	
D700 Dist – Street Lighting													X

1/ Actual amounts identified in Distribution Plant Study and are included in D300, D400 and D500.

Substations

D100 Distribution – Substations Non-Bulk Delivery is classified as demand.
D123 Distribution – Substations 23 kV Bulk Delivery is classified as demand.
D134 Distribution – Substations 34 kV Bulk Delivery is classified as demand.
D146 Distribution – Substations 46 kV Bulk Delivery is classified as demand.
D200 Distribution – Production. Step-up transformers at generating stations booked in distribution plant (D200) are sub-functionalized/classified as demand.

The above classifications are consistent with Minnesota Power's last five retail rate cases and are also consistent with the NARUC Manual's classification of substations (Chapter 5, page 73 and Chapter 6, pages 87 and 90).

Distribution Bulk Delivery (Sub-transmission)

D223 Distribution – Bulk Delivery Lines 23 kV is classified as demand.
D234 Distribution – Bulk Delivery Lines 34 kV is classified as demand.
D246 Distribution – Bulk Delivery Lines 46 kV is classified as demand.

The above classifications are consistent with Minnesota Power's last five retail rate cases and are also consistent with the NARUC Manual's classification of sub-transmission (distribution bulk delivery) facilities (Chapter 6, pages 87 and 90).

Demand and Customer Related

D300 Distribution – Overhead Lines is classified as demand and customer following the minimum system methodology.
D400 Distribution – Underground Lines is classified as demand and customer following the minimum system methodology.
D500 Distribution – Line Transformers is classified as demand and customer following the minimum system methodology.
D600 Distribution – Services is classified as demand and customer following the minimum system methodology.
D660 Distribution – Customer Premises – EV Charger plant is classified as demand and customer following D300 and D400 above.

The above classifications are consistent with Minnesota Power's last five retail rate cases. This is also consistent with the NARUC Manual's classification using the minimum system methodology, where the minimum system is classified as customer-related and the remaining portion is classified as demand-related (Chapter 6, page 87).

The minimum-size system was determined in the 2025 Distribution Plant Study where "the Minimum-Size Method" was employed. This method is outlined in the NARUC Manual (Chapter 6, page 90) and defined as follows:

> "[T]he minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable transformer and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each plant account, the minimum size distribution system is classified as customer-related costs."

Table 3 below summarizes customer and demand classification ratio results of the Distribution Plant Study. For more details, refer to the 2025 Distribution Plant Study in Volume 4, Workpapers.

Table 3

Based on 2025 Distribution Plant Study

Plant	FERC Account *Function Code*	Function	Customer Classification Minimum System %	Demand Classification %
Poles , Towers	364, 365	Primary Overhead Lines	42.91%	57.09%
OH Conductors	*D300*	Secondary Overhead Lines	37.84%	62.16%
UG Conduits, &	366, 367	Primary Underground Lines	30.39%	69.61%
Conductors	*D400*	Secondary Underground Lines	8.91%	91.09%
Line	368	Overhead Transformers	48.96%	51.04%
Transformers	*D500*	Underground Transformers	67.33%	32.67%
Services	3691	Overhead Services	88.88%	11.12%
	3692	Underground Services	35.06%	64.94%
	D600			

Customer Related

D650 Distribution – Metering Cost is classified as customer.
D675 Distribution – Leased Property is classified as customer.
D700 Distribution – Street Lighting is classified as customer.

The above classifications are consistent with Minnesota Power's last five retail rate cases with the exception of Meter costs. All of these classifications are consistent with the NARUC Manual's classification (Chapter 6, page 96).

Allocation of Distribution Plant – *Jurisdictional*

Table 4 below summarizes the methodologies to allocate distribution plant to jurisdiction and customer class. Each individual line item is presented in the same order as presented in Minnesota Power's CCOSS and is discussed below.

All facilities functionalized to Primary and Secondary Distribution are *only* used to serve Minnesota Power's retail customers, and therefore, there is no allocation across jurisdictions.

Table 4. Allocation of Distribution Plant

Basis of Jurisdictional Cost Allocation by Classification				
		Jurisdictional Allocation	Retail Class Allocation	
Function / Subfunction			Demand	Customer
Primary Overhead Lines		-	Class NCP	Customers
Primary Underground Lines		-	Class NCP	Customers
Secondary Overhead Lines		-	Sum NCP	Customers
Secondary Underground Lines		-	Sum NCP	Customers
Secondary OH lines transformers		-	Avg Class & Sum NCP	Customers
Secondary UG lines transformers		-	Avg Class & Sum NCP	Customers
Secondary OH services		-	Sum NCP	Customers
Secondary UG services		-	Sum NCP	Customers
EV Charger		-	Pri & Sec Lines	Customers
Leased Property		-	-	Direct
Street Lighting		-	-	Direct
Meters		Juris meters & cost:	1/3 each demand, energy & customer	
Production Demand	1/	12CP	4CP A&E	-
Distribution Bulk Delivery	2/	NCP	Class NCP	-
Distribution Substations		-	Class NCP	-
Dist. Bulk Delivery Specific Assign	3/	Direct	-	-
Dist. Primary Delivery Specific Assign	3/	Direct	-	-

1/ Step-up transformers at generating stations booked in distribution plant are subfuctionalized as production demand.
2/ Distribution Bulk Delivery are 23, 34 and 46 kV facilities that serve FERC and retail jurisdictional customers
3/ Specific Distribution 14 kV facilities and 23, 34, and 46 kV taps that serve FERC jurisdictional customers.

Meter costs are incurred to serve customers in both Minnesota Power's FERC and retail jurisdictions; thus, it is necessary to correctly allocate those costs between jurisdictions. The allocation is based on the total meter plant balance. The meter costs are first allocated by identifying (i) the original investment meter cost ("OIC") for each wholesale customer and (ii) the OIC for Large Power customers. These amounts, identified from specific plant records, are subtracted from the total meter costs.

> Total Meter Costs less OIC Meter Costs (Wholesale Customers) less OIC Meter Costs (Large Power) = Meter Costs to be allocated to Remaining Rate Classes

An average OIC is then calculated using the number of meters in each of the remaining rate classes and the meter costs in specific plant records. The remaining meter costs (miscellaneous cost) are subsequently split using ratios developed based on the number of miscellaneous small equipment identified in each rate class and its associated costs. The costs are then totaled by jurisdiction and class to develop the customer-related meter allocator (CC-DSMETERS).

Leased Property (CC-DLEASED) and Street Lighting (CC-DSLIGHTING) are lighting facilities directly assigned to Minnesota Power's retail Lighting Class.

Step-up transformers at generating stations recorded in distribution plant are sub-functionalized to production-demand and are allocated between jurisdictions based on the 12CP method following the method described above for the Production – Demand function (CC-PROD).

Distribution Bulk Delivery Plant are 23 kV, 34 kV, and 46 kV facilities that serve both FERC and retail jurisdictional customers. These facilities, sometimes referred to as sub-transmission, are used to deliver power on a more localized basis to the distribution system and are functionalized and kept distinct from power supply transmission facilities. Because the loads served off the distribution bulk delivery system are more localized in nature, their diversity is less than that on the power supply transmission system. Annual maximum non-coincident demands reflect the customer loads that are considered in designing this system and are therefore used for jurisdictional cost separation. The separation is accomplished by aggregating the non-coincident peak ("NCP") demands of all the FERC jurisdictional customers served from the distribution bulk delivery points of output and separately aggregating such demands for all retail customers. As a result, the retail jurisdictional responsibility is the retail aggregated demands divided by the total of the FERC and retail aggregated NCP demand (CC-DODBD).

Distribution Substations include substations that serve only the retail jurisdiction, and therefore, no allocation to the FERC jurisdiction is required.

Distribution Bulk Delivery Specific Assignment and Distribution Primary Specific Assignment are specific distribution 14 kV and 23 kV, 34 kV, and 46 kV facilities that serve *only* FERC jurisdictional customers, and therefore, the costs are directly assigned to the FERC jurisdiction.

Allocation of Distribution Plant – *Retail Classes*

As shown in Table 4 above, distribution facilities are allocated to retail classes based on how they are classified – that is, either with demand allocation factors (CC-DODBD through CC-DSUGS) or customer allocation factors (CC-DPOHL through CC-DSMETERS).

The customer-related costs determined for each function are allocated to the retail class primarily based on the average number of customers utilizing that function. The allocation to class of primary lines (CC-DPOHL, CC-DPUGL), secondary lines (CC-DSOHL, CC-DSUGL), transformers (CC-DSOHT, CC-DSUGT), and services (C-7, C-8) are all based on the number of customers served at that level of service. The analyses are based on the most recently available historical data, as well as from test year projected numbers of customers. Meter costs are allocated using the customer CC-DSMETERS allocators.

The remaining distribution plant is classified as demand-related costs, and therefore, these costs are allocated using allocation factors developed to reflect the appropriate demand associated with each function. Class NCP demand refers to the situation where one retail class of customers is segregated from all others. For such a class, there is one hour out of the 8,760 hours in the year when its combined load reaches a maximum point. This point is called the Class NCP (or Class Peak). Sum NCP demand differs from Class NCP demand in that the maximum demand for each of the customers within the class is determined independently. The sum of these maximum demands produces the Sum NCP (or Customer Peak) demand for such class.

The appropriate demand used for development of allocation factors varies depending on the system or functional cost being allocated. For example, since load diversity is recognized in system design and planning, it is proper to utilize a different demand in developing factors to allocate the costs associated with each system. For Distribution Bulk Delivery (CC-DODBD), Distribution Substations (CC-DODSUB), and Primary Line Facilities (CC-DPOHL, CC-DPUGL), an intermediate amount of diversity is apparent. Because of this, Class NCP demands calculated to the appropriate level of output are reasonable to use in developing these factors. There is somewhat less diversity in loads on Line Transformers (CC-DSOHT, CC-DSUGT), and so an average of Class NCP demands and Sum NCP demands calculated to the appropriate level of output are used. Finally, the least amount of diversity exists at the Secondary Lines (CC-DSOHL, CC-DSUGL) and Services level (CC-DSOHS, CC-DSUGS), and therefore, Sum NCP demands calculated to the appropriate level of output are used for allocating the demand-related cost of these facilities.

All of the above allocation methodologies for distribution plant are consistent with Minnesota Power's last five retail rate cases, as well as with our last FERC wholesale rate case for the FERC jurisdictional allocations. These methods are also consistent with the methods suggested by the NARUC Manual (Chapter 6, pages 96-99).

The development of the jurisdictional and class allocators are detailed in Volume 4, Workpapers, under Allocation Factors.

H. General Plant: FERC Accounts 389-399

General Plant is functionalized, classified, and allocated internally in the CCOSS model using labor ratios. *Refer to the description above of internally-developed allocators for additional information on internal allocators.*

Labor ratios based on Operation & Maintenance ("O&M" – Labor Only, excluding Administration & General ("A&G")) expenses are applied to assign General Plant to demand, energy, and customer classification and then to allocate to customer class. The use of labor ratios for the classification and allocation is one of the methods suggested by the NARUC Manual (Chapter 8, page 105).

This treatment is consistent with Minnesota Power's last five retail rate cases as well as our last FERC wholesale rate case.

I. Intangible Plant: FERC Accounts 301-303

Intangible is functionalized, classified, and allocated following the same treatment as General Plant described above.

J. Construction Work in Progress ("CWIP"): FERC Account 107

All CWIP is functionalized, classified, and allocated following the same methods as described above for the corresponding plant.

This treatment is consistent with Minnesota Power's last five retail rate cases and Minnesota Power's last FERC wholesale rate case. Additionally, the Company has assigned all Long-Range Transmission Planning ("LRTP") CWIP to the FERC jurisdiction as shown in reporting line Transmission Specific Assignment.

K. Accumulated Provision for Depreciation: FERC Accounts 108, 110

All Accumulated Provision for Depreciation amounts are functionalized, classified, and allocated following the corresponding plant-in-service. This treatment is consistent with Minnesota Power's last five retail rate cases and Minnesota Power's last FERC wholesale rate case.

L. Accumulated Provision for Amortization: FERC Accounts 111, 115

Accumulated Provision for Amortization amounts are functionalized, classified, and allocated following labor ratios as described above under General Plant. This treatment is consistent with Minnesota Power's last five retail rate cases and Minnesota Power's last FERC wholesale rate case.

M. Working Capital Requirements: FERC Accounts 151, 154, 163, 165

Fuel Inventory (FERC account 151) is classified as energy and is allocated to jurisdiction using energy allocator CC-PROD and to class using allocator CC-PROD/E8760. This treatment is the same as Fuel Expense (FERC account 501) discussed below. It is also consistent with Minnesota Power's last five retail rate cases, Minnesota Power's last FERC wholesale rate case, and also with the NARUC Manual (Chapter 4, page 36).

Materials and Supplies (FERC accounts 154 and 163) are sub-functionalized to production, transmission, and distribution on most recent calendar year FERC Form 1 amounts. Distribution is then sub-functionalized/classified on distribution plant-in-service ratios. All line items are allocated to jurisdiction and class following the same methods as described above for the corresponding plant. This treatment is consistent with Minnesota Power's last five retail rate cases and Minnesota Power's last FERC wholesale rate case.

Prepayments (FERC accounts 16500, 16500.07, 16510.1, 16580.005, 16580.002, 16580.0021, 16580.004, 16580.005, 16580.0051, 16580.0052, 16580.0053, 16580.0054, 16580.0011, and 16580.0021) are internally classified to demand, energy, and customer and are allocated to jurisdiction and class using an internal allocator based on plant. This treatment is consistent with Minnesota Power's last five retail rate cases and Minnesota Power's last FERC wholesale rate case.

Prepayment – Pension Asset (FERC accounts 18230.6015, 21900.0003, 22830.2008/9/11) are internally classified and allocated to demand, energy, and customer components following total O&M labor ratios less A&G. This approach is consistent with the approach followed in Minnesota Power's last five retail rate cases for other labor-related A&G costs and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case. This method is also discussed in the NARUC Manual (Chapter 8, page 106).

Prepayment – Silver Bay Power Corporation ("SBPC") (FERC account 18640.6023) is classified to energy and is allocated to jurisdiction using energy allocator CC-PROD and to class using allocator CC-PROD/E8760. This treatment is appropriate since the SBPC contract is energy-related and is the same used in Minnesota Power's last three retail rate cases.

Cash Working Capital items are assigned to demand, energy, and customer components and are allocated to jurisdiction and class using internal allocators calculated based on the corresponding expense. This treatment is consistent with Minnesota Power's last five retail rate cases and Minnesota Power's last FERC wholesale rate case.

Cash Working Capital Income Taxes are assigned to demand, energy, and customer components and are allocated to jurisdiction and class based on an internal allocator based on rate base.

N. Asset Retirement Obligation ("ARO"): FERC Accounts 23000, 18230

ARO is functionalized, classified, and allocated following the Production – Demand function. ARO is excluded from Interim and General Rates by Commission Order (Docket No. E015/GR-08/415).

O. Electric Vehicle Program: FERC Accounts 18640.0600, 18640.0600

Electric Vehicle Program capital costs are functionalized, classified, and allocated following the primary and secondary underground lines function.

P. Worker's Compensation Deposit: FERC Sub-Account 18640.0093

The Minnesota Power-regulated portion of the Worker's Compensation Deposit is internally classified and allocated to demand, energy, and customer components following total O&M labor ratios less A&G. This approach is consistent with the approach followed in Minnesota Power's last five retail rate cases for other labor-related A&G costs and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case. This method is also discussed in the NARUC Manual (Chapter 8, page 106).

Q. Unamortized Wisconsin Public Power, Inc. ("WPPI") Transmission Delivery: FERC Sub-Account 25300.9030

Unamortized WPPI payment for transmission services are amortized over a specific 33-year schedule. This reduction to rate base is functionalized to transmission, classified as demand, and allocated to jurisdiction and class based on the 12CP method (CC-TIPS).

R. Unamortized Upper Midwest Wind Initiative ("UMWI") Transaction Cost: FERC Sub-Account 18230.3003

Unamortized DC Line acquisition costs are amortized at 2.39 percent per year, and unamortized costs to restructure the Square Butte PPA are amortized over a specific 17-year schedule. These additions to rate base are functionalized to transmission, classified as demand, and allocated to jurisdiction and class based on the 12CP method (CC-TIPS).

S. Unamortized Boswell 1 & 2 Regulated Asset: FERC Sub-Account 18230.3011/13

Unamortized Boswell 1 & 2 Regulated Asset costs are functionalized to production, classified as demand, and allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

T. Customer Advances and Deposits: FERC Account 252, 253

Ideally, Customer Advances and Deposits should be assigned to the customer classes actually making the advances. Due to the large number of transactions, and because these transactions are recorded by FERC revenue class, they cannot be directly or readily separated into customer classes, particularly for General Service and Large Light & Power.

Because advances and deposits are made by customers requiring new service, it is reasonable to expect that the distribution of these new facilities by class would reflect the distribution of facilities to all customers in the long run. Therefore, as a proxy, Customer Advances and Deposits are functionally assigned, classified, and allocated to class following Primary and Secondary Overhead Lines.

This method has been used consistently in Minnesota Power's prior rate cases. This method was previously checked for reasonableness by manually reviewing over 1,000 transactions representing approximately 35 percent of the value of the Customer Advances and Deposits.

U. Other Deferred Credit – Hibbard: FERC Sub-Account 25300.9058/9

Other Deferred Credit – Hibbard is functionally assigned, classified, and allocated following Steam Plant – Demand. This approach is consistent with the treatment of Hibbard in rate base.

V. Wind Performance Deposit: FERC Sub-Account 25300.9091

Wind Performance Deposit is functionally assigned, classified, and allocated following Wind Plant – Demand. This approach is consistent with the treatment of wind plant in rate base.

W. Accumulated Deferred Income Taxes: FERC Accounts 281, 282, 283, 190

Accumulated Deferred Income Taxes are functionally assigned, classified, and allocated across jurisdiction and to class using internal allocators following plant-in-service. Because book/tax timing differences arise from investment in plant, it is reasonable these amounts should follow plant. This treatment is consistent with Minnesota Power's last five retail rate cases and Minnesota Power's last FERC wholesale rate case.

IV. INCOME STATEMENT

A. Summary of Approaches and Assumptions

Refer to Volume 3, Direct Schedule C-12, Summary of Approaches and Assumptions Used in Determining Operating Income for the Projected Fiscal Year and Proposed Test Year.

B. Sales of Electricity – Sales by Rate Class: FERC Accounts 440-447

The Revenue function contains the sales of electricity to the Minnesota jurisdictional and non-jurisdictional classes. Actual and budgeted sales are assigned to each rate class and are directly classified to demand, energy, and customer components based on actual and budgeted billing.

C. Sales of Electricity – Duel Fuel: FERC Accounts 440-443

Duel Fuel Sales are classified to demand and energy based on billings. Because all duel fuel sales are to Minnesota Power's retail customers, no allocation is made to the FERC jurisdiction.

Sales classified as demand are allocated to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD), and sales classified as energy are allocated to class using allocator CC-PROD/E8760.

All Duel Fuel Sales revenues are treated as revenue credits and allocated back to Minnesota Power's retail jurisdictional customers to recognize the system-wide benefit of interruptible customers.

D. Sales of Electricity – LP IPS, RFPS, SBPC, Economy: FERC Account 443

Sales revenue from Large Power Incremental Production Service ("IPS"), RFPS, SBPC, and Economy are classified as energy and are allocated to classes on energy (CC-PROD/E8760).

The revenues are treated a revenue credits and allocated back to Minnesota Power's FERC and retail jurisdictional customers.

This method of recognizing non-firm sales and distributing the revenues associated with these customers to all of the Company's standard retail and wholesale classes of customers is consistent with Minnesota Power's last five retail rate cases.

E. Sales of Electricity – Pool-Within-a-Pool: FERC Account 443

Pool-Within-a-Pool revenues are from a Large Power fixed charge related to RFPS or non-firm service. As with RFPS revenue, these revenues are treated as a revenue credit and are allocated back to all of the Company's standard retail and wholesale classes of customers.

These revenues are classified as demand and are allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

F. Intersystem Sales: FERC Account 447

Intersystem Sales are classified to demand and energy according to the details of each sale; that is, capacity sales are classified as demand, with remaining sales classified as energy.

Sales classified as demand are allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

Sales classified as energy are allocated to class on energy (CC-PROD/E8760). All Intersystem Sales revenues are treated as revenue credits and are allocated back to Minnesota Power's FERC and retail jurisdictional customers.

G. Other Operating Revenue: FERC Accounts 450, 454, 456

There are numerous sources of Other Operating Revenue in FERC accounts 450, 454, and 456. Each revenue type is reviewed and assigned to one of the following functions and classifications: Production – Demand, Production – Energy, Transmission, General Plant, Specific Retail – Energy, and Specific Retail – Distribution.

All Retail Specific revenue is allocated to Minnesota Power's retail customers only.

All RECB 26A Other Operating Revenue has been assigned to the FERC jurisdiction.

All Other Operating Revenues are treated as revenue credits and are allocated to jurisdiction and to class using the appropriate allocation factors.

Refer to Direct Schedule 2 attached to the Direct Testimony of Company witness Amanda L. Turner for a descriptive list of Other Operating Revenue.

H. Operation & Maintenance Expense – Steam Production: FERC Accounts 500-503, 505-506, 510-514

Steam O&M expenses are classified to demand and energy consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case. This treatment is similar to that shown in the NARUC Manual (Chapter 4, page 36).

Specifically, FERC accounts 510, 512, and 513 are classified to energy and all other expenses are classified as demand.

Fuel expense (account 501) is classified as energy and is described below.

Expenses classified as demand are allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

Expenses classified as energy are allocated to class on energy (CC-PROD/E8760).

I. Operation & Maintenance Expense – Hydro Production: FERC Accounts 535, 537-539, 541-545

Hydro O&M expenses are classified to demand and energy consistent with the approach approved in Minnesota Power's last four retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case. This treatment is similar to that shown in the NARUC Manual (Chapter 4, page 37).

Specifically, FERC accounts 543-545 are classified to energy and all other expenses are classified as demand.

Expenses classified as demand are allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

Expenses classified as energy are allocated to class on energy (CC-PROD/E8760).

J. Operation & Maintenance Expense – Wind Production: FERC Accounts 546-554, 558

Wind O&M expenses are classified to demand consistent with the approach approved in Minnesota Power's last three retail rate cases and consistent with that approved in Minnesota Power's Renewable Resources Rider.

These expenses are allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

K. Operation & Maintenance Expense – Energy Storage: FERC Account 578

Energy Storage O&M expenses are classified to demand.

These expenses are allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

L. Operation & Maintenance Expense – Transmission: FERC Accounts 560-562, 565-571, 573

O&M expenses – Transmission are classified to demand, consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case. This treatment follows the NARUC Manual (Chapter 5, page 75).

These expenses are allocated on an internal allocator (TPIS) that follows the three components of transmission plant: production, transmission, and Allowance for Funds Used During Construction ("AFUDC") contra. This composite allocator was used in the Company's last two retail rate cases.

All LRTP-related O&M expenses have been assigned to the FERC jurisdiction.

M. Operation & Maintenance Expense – Distribution – Meters: FERC Accounts 586, 597

O&M expenses – Distribution – Meters are classified as customer-related.

These expenses are allocated to jurisdiction and class using the customer Meter allocation factors (CC-DSMETERS).

N. Operation & Maintenance Expense – Distribution – Other Distribution: FERC Accounts 580-585, 587-590, 592-598

Distribution O&M expenses are directly mapped to Meters and Other Distribution, which includes Distribution Bulk Delivery. This is treatment is consistent with the Company's last two retail rate cases.

These expenses remain internally classified and allocated to demand and customer components following the classification and allocation of distribution plant, excluding meters.

O. Operation & Maintenance Expense – Other Power Supply: FERC Accounts 556-557

Other Power Supply O&M expenses are classified to demand consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case. This treatment is similar to that shown in the NARUC Manual (Chapter 4, page 38).

These expenses are allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

P. Operation & Maintenance Expense – Other Power Supply – Purchase Power: FERC Account 555

Other Power Supply O&M expenses – Purchase Power are classified to demand and energy according to the details of each purchase. This is consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology and that approved in Minnesota Power's last FERC wholesale rate case. This treatment follows that shown in the NARUC Manual (Chapter 4, page 38).

Expenses classified as demand are allocated to jurisdiction based on the 12CP method and to class based on the 4CP A&E method described above for the Production – Demand function (CC-PROD).

Expenses classified as energy are allocated to class on energy (CC-PROD/E8760).

Q. Operation & Maintenance Expense – Fuel: FERC Account 501

O&M expenses – Fuel are classified to energy consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota

Power's last FERC wholesale rate case. This treatment follows that shown in the NARUC Manual (Chapter 4, page 36).

Expenses classified as energy are allocated to class on energy (CC-PROD/E8760).

R. Operation & Maintenance Expense – Customer Accounting: FERC Accounts 901-904

O&M Expenses – Customer Accounting are classified as customer-related consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

These expenses are allocated to jurisdiction and class using the Customer Account allocator (CC-OMCACCOUNT). The allocator was developed using actual account expenses by work order and labor distribution. The development of this allocator is detailed in Volume 4, Workpapers, under Allocation Factors.

S. Operation & Maintenance Expense – Customer Service & Information: FERC Accounts 907-910

O&M Expenses – Customer Service and Information are classified as customer-related consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

These expenses are allocated to jurisdiction and class using the Customer Service allocator (CC-OMSERVICE). The allocator was developed using actual account expenses by work order and labor distribution. The development of this allocator is detailed in Volume 4, Workpapers, under Allocation Factors.

T. Operation & Maintenance Expense – Conservation Improvement Program ("CIP"): FERC Sub-Account 90806.0000

O&M Expenses – Conservation Improvement Program are classified as energy consistent with the approach approved in Minnesota Power's last four retail rate cases.

In the Company's 2008 rate case, Minnesota Power revised the Conservation Cost Recovery Charge ("CCRC") methodology so that it excludes the test year energy sales for exempt Large Power customers and thus more accurately reflects the test year retail sales subject to the CCRC. To reflect this change, Minnesota Power changed the allocation of CIP expenses from the E8760 allocator to the CC-CIP allocator that allocates CIP expenses to retail rate classes based on each class's megawatt hour ("MWh") of energy subject to the CCRC.

U. Operation & Maintenance Expense – Sales: FERC Account 913

O&M Expenses – Sales are classified as customer-related consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

These expenses are allocated to class using the Customer Sales allocator (CC-OMSALES). The allocator was developed using actual account expenses by work order and labor distribution. The development of this allocator is detailed in Volume 4, Workpapers, under Allocation Factors.

V. Operation & Maintenance Expense – Property Insurance: FERC Account 924

O&M Expenses – Property Insurance are internally classified and allocated to demand, energy, and customer components following utility plant-in-service ratios. This is consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

W. Operation & Maintenance Expense – Regulatory Expenses – Misc.: FERC Account 928

O&M Expenses – Regulatory Expenses – Miscellaneous are internally classified and allocated to demand, energy, and customer components following utility plant-in-service ratios. This is consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

X. Operation & Maintenance Expense – Regulatory Expenses – MISO: FERC Account 928

O&M Expenses – Regulatory Expenses – MISO are functionalized to Transmission and are allocated to jurisdiction and class based on the 12CP method as described above for the Transmission function. This treatment is consistent with the approach approved in Minnesota Power's last two retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

Y. Operation & Maintenance Expense – Advertising: FERC Account 930.1

O&M Expenses – Advertising are internally classified and allocated to demand, energy, and customer components and class following total O&M labor ratios less A&G. This is consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

Z. Operation & Maintenance Expense – Franchise Requirements: FERC Account 927

O&M Expenses – Franchise Requirements are internally classified and allocated to demand, energy, and customer components on total retail rate base. This is consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

AA. Operation & Maintenance Expense – Other A&G: FERC Accounts 920-921, 923, 925, 926, 930.2, 935

O&M Expenses – Other A&G are internally classified and allocated to demand, energy, and customer components on total O&M labor ratios less A&G. This is consistent with the approach

approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

BB. Operation & Maintenance Expense – Charitable Contributions: FERC Account 426.1

O&M Expenses – Charitable Contributions are internally classified and allocated to demand, energy, and customer components following total O&M labor ratios less A&G. This is consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

CC. Operation & Maintenance Expense – Interest on Customer Deposits: FERC Sub-Accounts 43100.1001, 43100.1002

O&M Expenses – Interest on Customer Deposits are internally classified and allocated to demand and customer components following rate base. This is consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

DD. Depreciation Expense: FERC Account 403

Depreciation expenses are functionalized, classified, and allocated following the corresponding plant-in-service.

This treatment is consistent with Minnesota Power's last five retail rate cases and Minnesota Power's last FERC wholesale rate case.

EE. Intangible Plant Amortization Expense: FERC Account 404

Intangible Plant Amortization expense is internally functionalized, classified, and allocated following General and Intangible Plant. This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

FF. UMWI Amortization Expense: FERC Accounts 406, 407.3

UMWI Amortization expense is functionalized, classified, and allocated on production-demand, which is the same treatment as the UMWI rate base item discussed above.

GG. ARO Accretion Expense: FERC Account 411.1

ARO Accretion expense is excluded in Interim and General Rates by MPUC Order.

HH. Boswell 1 & 2 Amortization Expense: FERC Account 40730.11

Boswell 1 & 2 Amortization expense is functionalized, classified, and allocated on production-demand, which is the same treatment as the Boswell 1 & 2 Regulated Asset rate base item discussed above.

II. Rate Case Expense Amortization: FERC Account 928

Rate Case Expense Amortization is functionalized, classified, and allocated following total retail rate base. This is consistent with the approach approved in Minnesota Power's last five retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

JJ. Property Taxes: FERC Account 408.1

Property Taxes are internally functionalized, classified, and allocated following corresponding plant-in-service ratios.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

KK. Payroll Taxes: FERC Account 408.1

Payroll Taxes are internally functionalized, classified, and allocated following corresponding labor-only expense ratios for Steam, Hydro, Wind, Solar, Distribution, and A&G. All others follow the treatment of related O&M expenses.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

LL. Air Quality Emission Expense, MN Wind Production Tax, and Solar Production Tax: FERC Account 408.1

Air Quality Emission expense, MN Wind Production Tax, and Solar Production Tax are functionalized to production, classified as energy, and are allocated to class on energy (CC-PROD/E8760). Solar Production Tax is excluded from Interim and General Rates as a rider adjustment.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases.

MM. Additions and Deductions to Income for Tax: FERC Accounts – Various

The numerous additions and deductions to income for tax are functionally assigned and allocated to jurisdiction and class primarily with internal allocators and ratios that best reflect cost causation for each item.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

The amount "Deduction to Income for Tax – Interest on Long Term Debt" is a part of what is termed Interest Synchronization. In the CCOSS the interest on long term debt is internally calculated in the model for the Total Company; the calculation is the weighted cost of long term debt multiplied by the Total Company average rate base in the model. The resulting amount is then classified and allocated to jurisdiction and class using an internal allocator developed on total average rate base ratios.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

NN. State Current Income Tax

The Net Operating Loss ("NOL") Reclass to Deferred Tax Benefit (Expense), State Depreciation Modification, and other adjustments are internally functionalized, classified, and allocated following plant-in-service ratios.

The CCOSS calculates and assigns income taxes by class based on the adjusted net taxable income of each jurisdiction, classification, and class as determined by the CCOSS.

Minnesota state income tax is calculated at the statutory tax rate of 9.8 percent multiplied by the state net taxable income.

OO. Federal Current Income Tax

Minnesota state income tax deduction is calculated as described above. The NOL Reclass to Deferred Tax Benefit (Expense) is internally functionalized, classified, and allocated following plant-in-service ratios. Federal income tax is calculated at the statutory tax rate of 21 percent multiplied by the federal net taxable income. Federal and other tax credits are deducted from the federal income tax calculated above to arrive at the total federal income tax.

The CCOSS calculates and assigns income taxes by class based on the adjusted net taxable income of each jurisdiction, classification, and class as determined by the CCOSS.

PP. Provision for Deferred Income Tax: FERC Accounts 410.1, 411.1

Provision for Deferred Income Tax is functionalized by plant and then classified and allocated to jurisdiction and class following corresponding plant.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

QQ. Investment Tax Credit: FERC Account 411.4

Investment Tax Credit is functionalized by plant and then classified and allocated to jurisdiction and class following corresponding plant.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

RR. Allowance for Funds Used During Construction: FERC Accounts 419.1, 432

AFUDC is functionalized, classified, and allocated to jurisdiction and class following the treatment of the corresponding CWIP.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

SS. Operation & Maintenance Expense – Labor Only

O&M Expenses – Labor Only are the labor expenses included in the total O&M expenses above. The labor-only expenses are broken out to allow labor ratios and allocators to be internally developed. Apart from using the resulting labor ratios and allocators to functionally assign certain rate base and income statement components, the labor-only expenses are not otherwise utilized in the CCOSS model.

The labor-only expenses are internally functionalized, classified, and allocated to demand, energy, and customer components following the treatment of O&M expenses discussed above.

This treatment is consistent with the approach approved in Minnesota Power's last five retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC wholesale rate case.

The labor-only classification allocators are shown Volume 3, Direct Schedule E-3, Part 5c and the labor-only customer class allocators are shown Volume 3, Direct Schedule E-3, Part 7c.

Refer to description above of internally-developed allocators for further information on the internally-developed labor ratios and allocators.

Previous FERC Account	New FERC Account	Function	Description	Reporting Line Previous	Reporting Line New
51301	51311	Steam Production Generation	Maint (outage) of Electric Plant	O&M Expenses - Steam	O&M Expenses - Steam
54600	55801	Solar Generation	Operation Supervision and Engineering	O&M Expenses - Wind	O&M Expenses - Solar
54600	55813	Wind Generation	Operation Supervision and Engineering	O&M Expenses - Wind	O&M Expenses - Wind
54800	55802	Solar Generation	Solar Panel Generation and Other Plant Operating	O&M Expenses - Wind	O&M Expenses - Solar
54900	55802	Solar Generation	Solar Panel Generation and Other Plant Operating	O&M Expenses - Wind	O&M Expenses - Solar
54800	55814	Wind Generation	Wind Turbine Generation and Other Plant Operating Expenses	O&M Expenses - Wind	O&M Expenses - Wind
55000	55804	Solar Generation	Rents	O&M Expenses - Wind	O&M Expenses - Solar
55000	55816	Wind Generation	Rents	O&M Expenses - Wind	O&M Expenses - Wind
55100	57801	Energy Storage	Maint Supervision and Engineering	O&M Expenses - Wind	O&M Expenses - Energy Storage
55200	55807	Solar Generation	Maint of Solar Panels, Structures, and Equipment	O&M Expenses - Wind	O&M Expenses - Solar
55300	55807	Solar Generation	Maint of Solar Panels, Structures, and Equipment	O&M Expenses - Solar	O&M Expenses - Solar
55300	55819	Wind Generation	Maint of Wind Turbines, Structures, and Equipment	O&M Expenses - Wind	O&M Expenses - Wind
55400	55811	Solar Generation	Maint of Misc Solar Generation Plant	O&M Expenses - Wind	O&M Expenses - Solar
55400	55823	Wind Generation	Maint of Misc Wind Generation Plant	O&M Expenses - Wind	O&M Expenses - Wind
93500	51302	Steam Production Generation	Maint of Computer Software	O&M Expenses - A&G-Other A&G	O&M Expenses - Steam
93500	51303	Steam Production Generation	Maint of Communication Equipment	O&M Expenses - A&G-Other A&G	O&M Expenses - Steam
93500	54403	Hydraulic Power Generation	Maint of Communication Equipment	O&M Expenses - A&G-Other A&G	O&M Expenses - Hydro
93500	55809	Solar Generation	Maint of Computer Software	O&M Expenses - A&G-Other A&G	O&M Expenses - Solar
93500	59203	Distribution Expenses	Maint of Computer Software	O&M Expenses - A&G-Other A&G	O&M Expenses - Distribution-Other
93500	59204	Distribution Expenses	Maint of Communication Equipment	O&M Expenses - A&G-Other A&G	O&M Expenses - Distribution-Other
93500	93501	A&G Expenses	Maint of Computer Hardware	O&M Expenses - A&G-Other A&G	O&M Expenses - A&G-Other A&G
93500	93502	A&G Expenses	Maint of Computer Software	O&M Expenses - A&G-Other A&G	O&M Expenses - A&G-Other A&G
93500	93503	A&G Expenses	Maint of Communication Equipment	O&M Expenses - A&G-Other A&G	O&M Expenses - A&G-Other A&G

Table 5 Summary of Functionalization, Classification and Allocation in MP's CCOSS

Line	Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Plant Account or Function Code	Note	Name of Classification Allocator 11/	Classification			Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name of Customer Class Allocator 12/
					Demand	Energy	Customer				
	RATE BASE										
1	**PLANT IN SERVICE (PIS)**										
2	STEAM										
3	PRODUCTION - DEMAND	310-316		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
4	STEAM CONTRA			C-STEAM	X	-	-	Direct	-	(I)	CC-STEAMPIS-C
5	HYDRO										
6	PRODUCTION - DEMAND	330-336		C-HYDRO	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
7	PRODUCTION - ENERGY	B200	2/	C-HYDRO	-	X	-	E-01	E8760	(E)	CC-PROD
8	HYDRO CONTRA - DEMAND			C-HYDRO	X	-	-	Direct	-	(I)	CC-HYDROPIS-C
9	HYDRO CONTRA - ENERGY			C-HYDRO	-	X	-	Direct	-	(I)	CC-HYDROPIS-C
10	WIND										
11	PRODUCTION - DEMAND	340-346		C-WIND	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
12	WIND CONTRA			C-WIND	X	-	-	Direct	-	(I)	CC-WINDPIS-C
13	SOLAR										
14	PRODUCTION - DEMAND	341, 344 345		C-SOLAR	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
15	TRANSMISSION										
16	TRANSMISSION PRODUCTION	C200	3/	C-TPIS	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
17	TRANSMISSION	350-359		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TRAN
18	TRANMISSION CONTRA			C-TPIS	X	-	-	Direct	-	(I)	CC-TPIS-C
19	DISTRIBUTION	360-373	4/								
20	PRIMARY										
21	OVERHEAD LINES - DEMAND	D300		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
22	OVERHEAD LINES - CUSTOMER	D300		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
23	UNGRD LINES - DEMAND	D400		C-DPUGL	X	-	-	-	Class NCP	(E)	CC-DPUGL
24	UNGRD LINES - CUSTOMER	D400		C-DPUGL	-	-	X	-	Customers	(E)	CC-DPUGL
25	SECONDARY										
26	OVHD LINES - DEMAND	D300		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
27	OVHD LINES - CUSTOMER	D300		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
28	UNGRD LINES - DEMAND	D400		C-DSUGL	X	-	-	-	Sum NCP	(E)	CC-DSUGL
29	UNGRD LINES - CUSTOMER	D400		C-DSUGL	-	-	X	-	Customers	(E)	CC-DSUGL
30	OVHD LINE TRANSFRM - DEMAND	D500		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSOHT
31	OVHD LINE TRANSFRMS - CUSTOMER	D500		C-DSOHT	-	-	X	-	Customers	(E)	CC-DSOHT
32	UNGRD LINE TRANSFRMS - DEMAND	D500		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSUGT
33	UNGRD LINE TRANSFRMS - CUSTOMER	D500		C-DSUGT	-	-	X	-	Customers	(E)	CC-DSUGT
34	OVHD SERVICES - DEMAND	369.1		C-DSOHS	X	-	-	-	Sum NCP	(E)	CC-DSOHS
35	OVHD SERVICES - CUSTOMER	369.1		C-DSOHS	-	-	X	-	Customers	(E)	CC-DSOHS
36	UNGRD SERVICES - DEMAND	369.2		C-DSUGS	X	-	-	-	Sum NCP	(E)	CC-DSUGS
37	UNGRD SERVICES - CUSTOMER	369.2		C-DSUGS	-	-	X	-	Customers	(E)	CC-DSUGS
38	LEASED PROPERTY	372		C-CUSTOMER	-	-	X	-	Direct	(E)	CC-DSLEASED
39	STREET LIGHTING	373		C-CUSTOMER	-	-	X	-	Direct	(E)	CD-DSLIGHTING
40	DISTRIBUTION OTHER										
41	METERS	370		C-METERS	-	-	X	Juris Meters	Customers	(E)/(I)	CC-DSMETERS
42	PRODUCTION - DEMAND	D200	5/	C-DEMAND	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
43	DISTRIBUTION BULK DELIVERY	D223, D234, D246	6/	C-DEMAND	X	-	-	NCP	Class NCP	(E)	CC-DODBD
44	DISTRIBUTION SUBSTATIONS	D100		C-DEMAND	X	-	-	-	Class NCP	(E)	CC-DODSUB
45	DIST BULK DEL SPECIFIC ASSIGN	various	7/	C-DEMAND	X	-	-	Direct	-	(E)	CC-DSA
46	DIST PRIMARY SPECIFIC ASSIGN	various		C-DEMAND	X	-	-	Direct	-	(E)	CC-DSA
47	DISTRIBUTION SUBSTATIONS SPEC AASIGN			C-DEMAND	X	-	-	Direct	-	(E)	CC-DSA
48	DISTRIBUTION CONTRA			C-DPPIS	X	-	X	Direct	-	(I)	CC-DPPIS
49	GENERAL PLANT										
50	GENERAL PLANT	389-399		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
51	GENERAL PLANT CONTRA	389-399		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
52	INTANGIBLE PLANT										
53	INTANGILBE PLANT	301-303		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	C-OMLXAG
54	**CONSTRUCTION WORK IN PROGRESS**										
55	STEAM										
56	PRODUCTION - DEMAND	107		C-STEAMCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
57	STEAM CONTRA			C-STEAMCWIP	X	-	-	Direct	-	(I)	CC-STEAMCWIP-C
58	HYDRO										
59	PRODUCTION - DEMAND	107		C-HYDROCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
60	PRODUCTION - ENERGY	107		C-HYDROCWIP	-	X	-	E-01	E8760	(E)	CC-PROD
61	HYDRO CONTRA - DEMAND			C-HYDROCWIP	X	-	-	Direct	-	(I)	CC-HYDROCWIP-C
62	HYDRO CONTRA - ENERGY			C-HYDROCWIP	-	X	-	Direct	-	(I)	CC-HYDROCWIP-C
63	WIND										
64	PRODUCTION - DEMAND	107		C-WINDCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
65	WIND CONTRA			C-WINDCWIP	X	-	-	Direct	-	(I)	CC-WINDCWIP-C
66	SOLAR										
67	PRODUCTION - DEMAND	107		C-SOLARCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
68	TRANSMISSION										
69	TRANSMISSION PRODUCTION	107		C-TCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
70	TRANSMISSION	107		C-TCWIP	X	-	-	12 CP	12 CP	(E)	CC-TRAN
71	TRANMISSION CONTRA			C-TCWIP	X	-	-	Direct	-	(I)	CC-TCWIP-C
72	DISTRIBUTION	107									
73	PRIMARY										
74	OVERHEAD LINES - DEMAND	D300		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
75	OVERHEAD LINES - CUSTOMER	D300		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
76	UNGRD LINES - DEMAND	D400		C-DPUGL	X	-	-	-	Class NCP	(E)	CC-DPUGL
77	UNGRD LINES - CUSTOMER	D400		C-DPUGL	-	-	X	-	Customers	(E)	CC-DPUGL
78	SECONDARY										
79	OVHD LINES - DEMAND	107		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
80	OVHD LINES - CUSTOMER	107		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
81	UNGRD LINES - DEMAND	107		C-DSUGL	X	-	-	-	Sum NCP	(E)	CC-DSUGL
82	UNGRD LINES - CUSTOMER	107		C-DSUGL	-	-	X	-	Customers	(E)	CC-DSUGL
83	OVHD LINE TRANSFRM - DEMAND	107		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSOHT
84	OVHD LINE TRANSFRMS - CUSTOMER	107		C-DSOHT	-	-	X	-	Customers	(E)	CC-DSOHT
85	UNGRD LINE TRANSFRMS - DEMAND	107		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSUGT
86	UNGRD LINE TRANSFRMS - CUSTOMER	107		C-DSUGT	-	-	X	-	Customers	(E)	CC-DSUGT
87	OVHD SERVICES - DEMAND	369		C-DSOHS	X	-	-	-	Sum NCP	(E)	CC-DSOHS
88	OVERHEAD SERVICES - CUSTOMER	369		C-DSOHS	-	-	X	-	Customers	(E)	CC-DSOHS
89	UNGRD SERVICES - DEMAND	369		C-DSUGS	X	-	-	-	Sum NCP	(E)	CC-DSUGS
90	UNGRD SERVICES - CUSTOMER	369		C-DSUGS	-	-	X	-	Customers	(E)	CC-DSUGS
91	LEASED PROPERTY	372		C-CUSTOMER	-	-	X	-	Direct	(E)	CC-DSLEASED
92	STREET LIGHTING	373		C-CUSTOMER	-	-	X	-	Direct	(E)	CD-DSLIGHTING

Table 5 Summary of Functionalization, Classification and Allocation in MP's CCOSS

Line	Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Plant Account or Function Code	Note	Name of Classification Allocator 11/	Classification			Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name of Customer Class Allocator 12/
					Demand	Energy	Customer				
93	DISTRIBUTION OTHER										
94	METERS	107		C-METERS	-	-	X	Juris Meters	Customers	(E)/(I)	CC-DSMETERS
95	PRODUCTION - DEMAND	107		C-DEMAND	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
96	DISTRIBUTION BULK DELIVERY			C-DEMAND	X	-	-	NCP	Class NCP	(E)	CC-DODBD
97	DISTRIBUTION SUBSTATIONS	107		C-DEMAND	X	-	-	-	Class NCP	(E)	CC-DODSUB
98	DIST BULK DEL SPECIFIC ASSIGN			C-DEMAND	X	-	-	Direct	-	(E)	CC-DSA
99	DIST PRIMARY SPECIFIC ASSIGN	107		C-DEMAND	X	-	-	Direct	-	(E)	CC-DSA
100	GENERAL PLANT										
101	GENERAL PLANT	107		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
102	GENERAL PLANT CONTRA	107		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
103	INTANGIBLE PLANT										
104	INTANGILBE PLANT	107		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
105	**ACCUMULATED DEPRECIATION (AD)**										
106	STEAM										
107	PRODUCTION - DEMAND	108, 110		C-Steam	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
108	STEAM CONTRA			C-Steam	X	-	-	Direct	-	(I)	CC-STEAMAD-C
109	HYDRO										
110	PRODUCTION - DEMAND	108, 110		C-Hydro	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
111	PRODUCTION - ENERGY	108, 110		C-Hydro	-	X	-	E-01	E8760	(E)	CC-PROD
112	HYDRO CONTRA - DEMAND			C-Hydro	X	-	-	Direct	-	(I)	CC-HYDROAD-C
113	HYDRO CONTRA - ENERGY			C-Hydro	-	X	-	Direct	-	(I)	CC-HYDROAD-C
114	WIND										
115	PRODUCTION - DEMAND	108, 110		C-Wind	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
116	WIND CONTRA			C-Wind	X	-	-	Direct	-	(I)	CC-WINDAD-C
117	SOLAR										
118	PRODUCTION - DEMAND	108, 110		C-Solar	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
119	TRANSMISSION										
120	TRANSMISSION PRODUCTION	108, 110		C-TPIS	X	-	-	12 CP	4CP A&E	(E)	CC-TPISXCONTRA
121	TRANSMISSION	108, 110		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPISXCONTRA
122	TRANMISSION CONTRA			C-TPIS	X	-	-	Direct	-	(I)	CC-TAD-C
123	DISTRIBUTION	108, 110									
124	PRIMARY										
125	OVERHEAD LINES - DEMAND	108, 110		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
126	OVERHEAD LINES - CUSTOMER	108, 110		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
127	UNGRD LINES - DEMAND	108, 110		C-DPUGL	X	-	-	-	Class NCP	(E)	CC-DPUGL
128	UNGRD LINES - CUSTOMER	108, 110		C-DPUGL	-	-	X	-	Customers	(E)	CC-DPUGL
129	SECONDARY										
130	OVHD LINES - DEMAND	108, 110		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
131	OVHD LINES - CUSTOMER	108, 110		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
132	UNGRD LINES - DEMAND	108, 110		C-DSUGL	X	-	-	-	Sum NCP	(E)	CC-DSUGL
133	UNGRD LINES - CUSTOMER	108, 110		C-DSUGL	-	-	X	-	Customers	(E)	CC-DSUGL
134	OVHD LINE TRANSFRM - DEMAND	108, 110		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSOHT
135	OVHD LINE TRANSFRMS - CUSTOMER	108, 110		C-DSOHT	-	-	X	-	Customers	(E)	CC-DSOHT
136	UNGRD LINE TRANSFRMS - DEMAND	108, 110		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSUGT
137	UNGRD LINE TRANSFRMS - CUSTOMER	108, 110		C-DSUGT	-	-	X	-	Customers	(E)	CC-DSUGT
138	OVHD SERVICES - DEMAND	108, 110		C-DSOHS	X	-	-	-	Sum NCP	(E)	CC-DSOHS
139	OVERHEAD SERVICES - CUSTOMER	108, 110		C-DSOHS	-	-	X	-	Customers	(E)	CC-DSOHS
140	UNGRD SERVICES - DEMAND	108, 110		C-DSUGS	X	-	-	-	Sum NCP	(E)	CC-DSUGS
141	UNGRD SERVICES - CUSTOMER	108, 110		C-DSUGS	-	-	X	-	Customers	(E)	CC-DSUGS
142	LEASED PROPERTY	108, 110		C-CUSTOMER	-	-	X	-	Direct	(E)	CC-DSLEASED
143	STREET LIGHTING	108, 110		C-CUSTOMER	-	-	X	-	Direct	(E)	CD-DSLIGHTING
144	DISTRIBUTION OTHER										
145	METERS	108, 110		C-METERS	-	-	X	Juris Meters	Customers	(E)/(I)	CC-DSMETERS
146	PRODUCTION - DEMAND	108, 110		C-DEMAND	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
147	DISTRIBUTION BULK DELIVERY			C-DEMAND	X	-	-	NCP	Class NCP	(E)	CC-DODBD
148	DISTRIBUTION SUBSTATIONS	108, 110		C-DEMAND	X	-	-	-	Class NCP	(E)	CC-DODSUB
149	DIST BULK DEL SPECIFIC ASSIGN			C-DEMAND	X	-	-	Direct	-	(E)	CC-DODBDSA
150	DIST PRIMARY SPECIFIC ASSIGN	108, 110		C-DEMAND	X	-	-	Direct	-	(E)	CC-DODPSA
151	DISTRIBUTION CONTRA			C-DPAD	X	-	X	Direct	-	(I)	CC-DPAD
152	GENERAL PLANT										
153	GENERAL PLANT	108, 110		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
154	GENERAL PLANT CONTRA			C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
155	INTANGIBLE PLANT										
156	INTANGILBE PLANT	111, 115		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
157	**WORKING CAPITAL REQUIREMENTS**										
158	FUEL INVENTORY	151		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
159	MATERIALS & SUPPLIES	154, 163	8/								
160	PRODUCTION - DEMAND	154, 163		C-MSPROD	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
161	TRANSMISSION	154, 163		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
162	DISTRIBUTION - PRIMARY										
163	OVERHEAD LINES - DEMAND	154, 163		C-DPIS	X	-	-	-	Class NCP	(E)	CC-DPIS
164	OVERHEAD LINES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
165	UNGRD LINES - DEMAND	154, 163		C-DPIS	X	-	-	-	Class NCP	(E)	CC-DPIS
166	UNGRD LINES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
167	DISTRIBUTION - SECONDARY										
168	OVHD LINES - DEMAND	154, 163		C-DPIS	X	-	-	-	Sum NCP	(E)	CC-DPIS
169	OVHD LINES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
170	UNGRD LINES - DEMAND	154, 163		C-DPIS	X	-	-	-	Sum NCP	(E)	CC-DPIS
171	UNGRD LINES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
172	OVHD LINE TRANSFRM - DEMAND	154, 163		C-DPIS	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DPIS
173	OVHD LINE TRANSFRMS - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
174	UNGRD LINE TRANSFRMS - DEMAND	154, 163		C-DPIS	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DPIS
175	UNGRD LINE TRANSFRMS - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
176	OVHD SERVICES - DEMAND	154, 163		C-DPIS	X	-	-	-	Sum NCP	(E)	CC-DPIS
177	OVERHEAD SERVICES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
178	UNGRD SERVICES - DEMAND	154, 163		C-DPIS	X	-	-	-	Sum NCP	(E)	CC-DPIS
179	UNGRD SERVICES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
180	LEASED PROPERTY	154, 163		C-CUSTOMER	-	-	X	-	Direct	(E)	CC-DPIS
181	STREET LIGHTING	154, 163		C-CUSTOMER	-	-	X	-	Direct	(E)	CC-DPIS
182	DISTRIBUTION OTHER										
183	METERS	154, 163		C-DEMAND	-	-	X	Juris Meters	Customers	(E)/(I)	CC-DPIS
184	PRODUCTION - DEMAND	154, 163		C-DEMAND	X	-	-	12 CP	4CP A&E	(E)	CC-DPIS
185	DISTRIBUTION BULK DELIVERY			C-DEMAND	X	-	-	NCP	Class NCP	(E)	CC-DPIS

Table 5 Summary of Functionalization, Classification and Allocation in MP's CCOSS

Line	Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Plant Account or Function Code	Note	Name of Classification Allocator 11/	Classification Demand	Classification Energy	Classification Customer	Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name of Customer Class Allocator 12/
186	DISTRIBUTION SUBSTATIONS	154, 163		C-DEMAND	X	-	-	-	Class NCP	(E)	CC-DPIS
187	DIST BULK DEL SPECIFIC ASSIGN			C-DEMAND	X	-	-	Direct	-	(E)	CC-DPIS
188	DIST PRIMARY SPECIFIC ASSIGN	154, 163		C-DEMAND	X	-	-	Direct	-	(E)	CC-DPIS
189	OTHER PREPAYMENTS	16500, 16510.1, 16580.005, 16580.002, 16580.0021, 16580.004, 16580.005, 16580.0051-4, 16580.0011, 16580.0021		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
190	PREPAYMENTS - PENSION ASSET	18230.6015, 21900.0003, 22830.20008/9/11		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
191	PREPAYMENTS - OPEB	12800.2012, 18640.0047, 21900.0004, 22830.2004/5/6, 25400.1001		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	CC-OMLXAG
192	PREPAYMENTS - SBPC	18640.6023		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
193	CASH WORKING CAPITAL	-	9/								
194	O&M EXPENSES	-									
195	FUEL	-		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
196	PURCHASED POWER	-		C-PPOWER	X	X	-	Total Purchased Power Exp		(I)	CC-PPOWER
197	PAYROLL	-		C-OMLXFPP	X	X	X	Total O&M Labor Excluding PP		(I)	CC-OMLXFPP
198	OTHER O&M	-		C-OMEXPCWC	X	X	X	O&M Expense CWC		(I)	CC-OMEXPCWC
199	PROPERTY TAXES	-		C-PROPTAX	X	X	X	Total Property Taxes		(I)	CC-PROPTAX
200	PAYROLL TAXES	-		C-OMLABOR	X	X	X	Total O&M Labor		(I)	CC-OMLABOR
201	AIR QUALITY EMISSION TAX	-		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
202	MINNESOTA WIND PRODUCTION TAX			C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
203	MINNESOTA SOLAR PRODUCTION TAX			C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
204	SALES TAX COLLECTIONS	-		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
205	INCOME TAXES	-		C-RATEBASE	X	X	X	Rate Base		(I)	CC-RATEBASE
206	INCOME TAXES (INCREASE)	-		C-RATEBASE	X	X	X	-	Rate Base	(I)	CC-RATEBASEMN
207	**ASSET RETIREMENT OBLIGATION**	23000, 18230		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
208	**ELECTRIC VEHICLE PROGRAM**	18640.0553		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
209	**WORKERS COMP DEPOSIT**	18640.0093		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLAXAG
210	**UNAMORTIZED WPPI TRANSM AMORT**	25300.9030		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
211	**UNAMORTIZED UMWI TRANSACTION COST**	18230.3003		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
212	**UNAMORTIZED BOS 1 and 2**	18230.3011/13		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
213	**CUSTOMER ADVANCES**			C-DOHL						(I)	CC-DOHL
214	PRIMARY OVHD LINES - DEM	252		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
215	PRIMARY OVHD LINES - CUST	252		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
216	SECONDARY OVHD LINES - DEM	252		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
217	SECONDARY OVHD LINES - CUST	252		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
218	**CUSTOMER DEPOSITS**	235		C-DOHL	X	-	X	Total Customer Advances		(I)	CC-ADVANCES
219	**OTHER DEFERRED CREDITS - HIBBARD**	25300.9058/9		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
220	**WIND PERFORMANCE DEPOSIT**	25300.9091		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
221	**ACCUMULATED DEFERRED INCOME TAXES**										
222	STEAM - Cr	281-3		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
223	HYDRO - Cr	281-3		C-HYDRO	X	X	-	Hydo PIS		(I)	CC-HYDRO
224	WIND - Cr	281-3		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
225	SOLAR - Cr	281-3		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
226	TRANSMISSION - Cr	281-3		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
227	DISTRIBUTION - Cr	281-3		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
228	GENERAL - Cr	281-3		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
229	STEAM - Dr	190		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
230	HYDRO - Dr	190		C-HYDRO	X	X	-	Hydo PIS		(I)	CC-HYDRO
231	WIND - Dr	190		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
232	SOLAR - Dr	190		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
233	TRANSMISSION - Dr	190		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
234	DISTRIBUTION - Dr	190		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
235	GENERAL - Dr	190		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
236											
237	**OPERATING INCOME**										
238	**OPERATING REVENUES**										
239	REVENUE FROM SALES BY RATE CLASS AND DUAL FUEL										
240	SALES BY RATE CLASS	440-447		C-RSALES	X	X	X	Direct	Direct	(I)	CC-RSALES
241	DUAL FUEL DEMAND	440-443		C-RDUALFUEL	X	-	-	-	4CP A&E	(E)	CC-PRODMN
242	DUAL FUEL ENERGY	440-443		C-RDUALFUEL	-	X	-	-	E8760	(E)	CC-PRODMN
243	OTHER REVENUE FROM SALES										
244	INTERSYSTEM SALES DEMAND	443		C-RISSALES	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
245	INTERSYSTEM SALES ENERGY	443		C-RISSALES	-	X	-	E-01	E8760	(E)	CC-PROD
246	LP DEMAND RESPONSE	443		C-DEMAND	X	-	-	-	4CP A&E	(E)	CC-PRODMN
247	SALES FOR RESALE DEMAND	447		C-RRESALE	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
248	SALES FOR RESALE ENERGY	447		C-RRESALE	-	X	-	E-01	E8760	(E)	CC-PROD
249	OTHER OPERATING REVENUE (OOR)										
250	ORR - PRODUCTION DEMAND	454, 456.1, 456.4		C-RPROD	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
251	ORR - PRODUCTION ENERGY	456.9		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
252	ORR - TRANSMISSION	454, 456.2, 456.6, 456.9		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
253	ORR - DISTRIBUTION	450, 456.9		C-DPISXCONTRA						(I)	C-DPISXCONTRA
254	DISTRIBUTION - PRIMARY										
255	OVERHEAD LINES - DEMAND	450, 456.9		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
256	OVERHEAD LINES - CUSTOMER	450, 456.9		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
257	UNGRD LINES - DEMAND	450, 456.9		C-DPUGL	X	-	-	-	Class NCP	(E)	CC-DPUGL
258	UNGRD LINES - CUSTOMER	450, 456.9		C-DPUGL	-	-	X	-	Customers	(E)	CC-DPUGL
259	DISTRIBUTION - SECONDARY										
260	OVHD LINES - DEMAND	450, 456.9		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
261	OVHD LINES - CUSTOMER	450, 456.9		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
262	UNGRD LINES - DEMAND	450, 456.9		C-DSUGL	X	-	-	-	Sum NCP	(E)	CC-DSUGL
263	UNGRD LINES - CUSTOMER	450, 456.9		C-DSUGL	-	-	X	-	Customers	(E)	CC-DSUGL
264	OVHD LINE TRANSFRM - DEMAND	450, 456.9		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSOHT
265	OVHD LINE TRANSFRMS - CUSTOMER	450, 456.9		C-DSOHT	-	-	X	-	Customers	(E)	CC-DSOHT
266	UNGRD LINE TRANSFRMS - DEMAND	450, 456.9		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSUGT
267	UNGRD LINE TRANSFRMS - CUSTOMER	450, 456.9		C-DSUGT	-	-	X	-	Customers	(E)	CC-DSUGT
268	OVHD SERVICES - DEMAND	450, 456.9		C-DSOHS	X	-	-	-	Sum NCP	(E)	CC-DSOHS
269	OVERHEAD SERVICES - CUSTOMER	450, 456.9		C-DSOHS	-	-	X	-	Customers	(E)	CC-DSOHS
270	UNGRD SERVICES - DEMAND	450, 456.9		C-DSUGS	X	-	-	-	Sum NCP	(E)	CC-DSUGS
271	UNGRD SERVICES - CUSTOMER	450, 456.9		C-DSUGS	-	-	X	-	Customers	(E)	CC-DSUGS

Table 5 Summary of Functionalization, Classification and Allocation in MP's CCOSS

Line	Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Plant Account or Function Code	Note	Name of Classification Allocator 11/	Classification Demand	Classification Energy	Classification Customer	Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name of Customer Class Allocator 12/
272	LEASED PROPERTY	450, 456.9		C-CUSTOMER	-	-	X	-	Direct	(E)	CC-DSLEASED
273	STREET LIGHTING	450, 456.9		C-CUSTOMER	-	-	X	-	Direct	(E)	CD-DSLIGHTING
274	DISTRIBUTION OTHER										
275	METERS	450, 456.9		C-METERS	-	-	X	Juris Meters	Customers	(E)/(I)	CC-DSMETERS
276	PRODUCTION - DEMAND	450, 456.9		C-DEMAND	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
277	DISTRIBUTION BULK DELIVERY	450, 456.9		C-DEMAND	X	-	-	NCP	Class NCP	(E)	CC-DODBD
278	DISTRIBUTION SUBSTATIONS	450, 456.9		C-DEMAND	X	-	-	-	Class NCP	(E)	CC-DODSUB
279	DIST BULK DEL SPECIFIC ASSIGN	450, 456.9		C-DEMAND	X	-	-	Direct	-	(E)	CC-DODBDSA
280	DIST PRIMARY SPECIFIC ASSIGN	450, 456.9		C-DEMAND	X	-	-	Direct	-	(E)	CC-DODPSA
281	GENERAL PLANT	450, 456.9		C-OMLXAG	X	X	X	General Plant		(I)	CC-OMLXAG
282	ORR - DISPOSITION OF ALLOWANCES	411.8		C-ENERGY	-	X	-	-	E8760	(E)	CC-PRODMN
283	ORR - CONSERVATION IMPROV PROGRAM	456.9		C-ENERGY	-	X	-	-	CCRC MWh	(E)	CC-CIP
284	ORR - RENEWABLE RESOURCES RIDER	456.9		C-RRR	X	X	-	12 CP	4CP A&E	(E)	CC-RRR
285	ORR - SOLAR RENEWABLE RESOURCES RIDER	456.9		C-SRRR	-	X	-	12 CP	4CP A&E	(E)	CC-SRRR
286	ORR - TRANSMISSION COST RECOVERY RIDER	456.9		C-TCR	X	X	-	12 CP	12 CP	(E)	CC-TCR
287	ORR - ELECTRIC VEHICLE PROGRAM	456.9		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
288	**OPERATION & MAINTENANCE EXPENSE**										
289	STEAM PRODUCTION										
290	DEMAND	500-3, 505/6, 511, 514		C-OMSTEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
291	ENERGY	510, 512-3		C-OMSTEAM	-	X	-	E-01	E8760	(E)	CC-PROD
292	HYDRO PRODUCTION										
293	DEMAND	535, 537-9, 541-2		C-OMHYDRO	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
294	ENERGY	543-5		C-OMHYDRO	-	X	-	E-01	E8760	(E)	CC-PROD
295	WIND PRODUCTION	546-554		C-OMWIND	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
296	ENERGY STORAGE	578		C-OMSTORAGE	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
297	TRANSMISSION	560-2, 565-571, 573		C-TPIS	X	-	-	12 CP	12 CP	(I)	CC-TPIS
298	DISTRIBUTION										
299	METERS	586, 597		C-METERS	-	-	X	Juris Meters	Customers	(E)/(I)	CC-DSMETERS
300	OTHER DISTRIBUTION	580-5, 587-590, 592-8		C-DPISXMETERS	X	-	X	Dist PIS, Excl Meters		(I)	CC-DPISXMETERS
301	OTHER POWER SUPPLY										
302	PRODUCTION DEMAND	556-7		C-POWER	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
303	PURCHASED POWER										
304	DEMAND	555		C-PPOWER	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
305	ENERGY	555		C-PPOWER	-	X	-	E-01	E8760	(E)	CC-PROD
306	FUEL	501		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
307	CUSTOMER ACCOUNTING	901-4		C-CUSTOMER	-	-	X	Expenses & Labor ratios		(E)	CC-OMACCOUNT
308	CUSTOMER SERVICE & INFORMATION	907-10		C-CUSTOMER	-	-	X	Expenses & Labor ratios		(E)	CC-OMSERVICE
309	CONSERV IMPROVEMENT PROGRAM	90806.0000		C-ENERGY	-	X	-	-	CCRC MWh	(E)	CC-CIP
310	SALES	913		C-CUSTOMER	-	-	X	Expenses & Labor ratios		(E)	CC-OMSALES
311	ADMINISTRATIVE & GENERAL										
312	PROPERTY INSURANCE	924		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
313	REGULATORY EXPENSES - MIS0	928		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
314	REGULATORY EXPENSES - MISC	928		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
315	RATE CASE EXPENSES	928		C-RATEBASE	X	X	X	-	Retail Rate Base	(I)	CC-RATEBASEMN
316	ADVERTISING	930.1		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
317	FRANCHISE REQUIREMENTS	927		C-RATEBASE	X	X	X	-	Retail Rate Base	(I)	CC-RATEBASEMN
318	OTHER ADMIN & GENERAL	920-1, 923, 925-6, 930.2		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
319	CHARITABLE CONTRIBUTIONS	426.1		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
320	INTEREST ON CUSTOMER DEPOSITS	43100.1001, 43100.1002		C-RATEBASE	X	X	X	Rate Base	Retail Rate Base	(I)	CC-RATEBASEMN
321	**DEPRECIATION EXPENSE**										
322	STEAM	403		C-STEAM	X	-	-	Steam PIS		(E)	CC-PROD
323	STEAM CONTRA			C-STEAM	X	-	-	Direct	4CP A&E	(E)	CC-STEAMDE-C
324	HYDRO DEMAND	403		C-HYDRO	X	-	-	Hydro PIS		(E)	CC-PROD
325	HYDRO ENERGY			C-HYDRO	-	X	-	Hydro PIS		(E)	CC-PROD
326	HYDRO CONTRA			C-HYDRO	X	-	-	Direct	4CP A&E	(E)	CC-HYDRODE-C
327	WIND	403		C-WIND	X	-	-	Wind PIS		(E)	CC-PROD
328	WIND CONTRA			C-WIND	X	-	-	Direct	4CP A&E	(E)	CC-WINDDE-C
329	SOLAR	403		C-SOLAR	X	-	-	Solar PIS		(E)	CC-PROD
330	TRANSMISSION	403		C-TPIS	X	-	-	Transmission PIS		(E)	CC-TPISXCONTRA
331	TRANSMISSION CONTRA			C-TPIS	X	-	-	Direct	12 CP	(E)	CC-TDE-C
332	DISTRIBUTION	403		C-DPISXCONTRA	X	-	X	Distribution PIS		(E)	CC-DPISXCONTRA
333	DISTRIBUTION CONTRA			C-DPAD	X	-	X	Distribution PIS		(E)	CC-DPAD
334	GENERAL PLANT	403		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
335	GENERAL PLANT CONTRA	403		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
336	**AMORTIZATION EXPENSE**										
337	INTANGIBLE PLANT	404		C-OMLXAG	X	X	X	General Plant		(I)	CC-OMLXAG
338	UMWI	406, 407.3		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
339	ARO ACCERTION	411.1		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
340	BOSWELL 1 AND 2	40730.11		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
341	**PROPERTY TAXES**										
342	STEAM	408.1		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
343	HYDRO	408.1		C-HYDRO	X	X	-	Total Hydro PIS		(I)	CC-HYDRO
344	WIND	408.1		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
345	SOLAR	408.1		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
346	TRANSMISSION	408.1		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPISXCONTRA
347	DISTRIBUTION	408.1		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
348	GENERAL PLANT	408.1		C-OMLXAG	X	X	X	Total General PIS		(I)	CC-OMLXAG
349	**PAYROLL TAXES**			C-OMLABOR						(I)	CC-OMLABOR
350	STEAM	408.1		C-OMLSTEAM	X	X	-	O&M Steam Labor		(I)	CC-OMLSTEAM
351	HYDRO	408.1		C-OMLHYDRO	X	X	-	O&M Hydro Labor		(I)	CC-OMLHYDRO
352	WIND	408.1		C-OMLWIND	X	X	-	O&M Wind Labor		(I)	CC-OMLWIND
353	SOLAR	408.1		C-OMLSOLAR	X	X	-	O&M Solar Labor		(I)	CC-OMLSOLAR
354	TRANSMISSION	408.1		C-TPIS	X	-	-	12 CP	12 CP	(I)	CC-TPIS
355	DISTRIBUTION	408.1		C-OMLD	X	-	X	O&M Distribution Labor		(I)	CC-OMLD
356	OTHER POWER SUPPLY	408.1		C-POWER	X	X	X	O&M Other Power Supply		(I)	CC-PROD
357	FUEL	408.1		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
358	CUSTOMER ACCOUNTING	408.1		C-CUSTOMER	-	-	X	O&M Expenses		(E)	CC-OMACCOUNT
359	CUSTOMER SERVICE & INFORMATION	408.1		C-CUSTOMER	-	-	X	O&M Expenses		(E)	CC-OMSERVICE
360	SALES	408.1		C-CUSTOMER	-	-	X	O&M Expenses		(E)	CC-OMSALES
361	ADMIN & GEN	408.1		C-OMLAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLAG
362	**AIR QUALITY EMISSION - PROD ENERGY**	408.1		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
363	**MINNESOTA WIND PRODUCTION TAX**	408.1		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
364	**MINNESOTA SOLAR PRODUCTION TAX**	408.1		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD

Table 5 Summary of Functionalization, Classification and Allocation in MP's CCOSS

Line	Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Plant Account or Function Code	Note	Name of Classification Allocator 11/	Classification Demand	Classification Energy	Classification Customer	Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name of Customer Class Allocator 12/
365	**ADDITIONS AND DEDUCTIONS TO INCOME FOR TAX**										
366	ACCRUED POST EMPL BNFTS -FAS 112 OPRTG	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
367	ACCRUED VACATION	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
368	ARO ACCRETION	various		C-EPIS	X	X	X	Steam Plant		(I)	CC-EPIS
369	ARO AMORTIZATION	various		C-STEAM	X	-	-	Steam Plant		(I)	CC-STEAM
370	BOND ISSUE COSTS (NCL)	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
371	BOSWELL TRANSMISSION AGREEMENT	various		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TRAN
372	CAPITALIZED OVERHEADS	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
373	CONSERVATION IMPROVEMENT PROJECT	various		C-ENERGY	-	X	-	-	CCRC MWh	(E)	CC-CIP
374	CONTRIBUTION IN AID OF CONSTRUCTION	various		C-DSOHL	X	X	-	Sum NCP & Customers		(E)	CC-DSOHL
375	COST TO RETIRE	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
376	DEFERRED NON-QUALIFIED PLANS (NCA)	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
377	DEFERRED NON-QUALIFIED PLANS - OPERATING	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
378	DIRECTOR FEES -DEFERRED	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
379	DUES	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
380	EIP DEATH BENEFIT	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
381	EPA NOV	various		C-STEAM	X	-	-	Steam Plant		(I)	CC-STEAM
382	ESPP DISQUALIFING DISPOSITION	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
383	FAS 158 - MONTHLY	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
384	FAS 158 - OCI ADJUSTMENT	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
385	FUEL CLAUSE ADJUSMENT	various		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
386	FUEL TAX CREDIT	various		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
387	INT LONG TERM DEBT (INT SYNCHRONIZATION)	various	10/	C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
388	MEALS AND ENTERTAINMENT	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
389	MEDICAL CLAIMS (CA)	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
390	MEDICARE SUBSIDY	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
391	MISO RESERVE	various		C-REGEXPMISO	X	-	-	12 CP	12 CP	(E)	CC-TRAN
392	ND ITC REGULATORY LIABILIY	various		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
393	NONDEDUCTIBLE PARKING	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
394	OPEB FAS 106 OPERATING	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
395	PENSION EXPENSE - OPERATING (NCA)	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
396	PERFORMANCE SHARES - FAW 123R	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
397	PENALTIES	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
398	POLITICAL ACTIVITIES	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
399	PREPAID BISON EASEMENTS	various		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
400	PREPAID INSURANCE	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
401	PROPERTY TAXES	various		C-PROPTAX	X	X	X	Total Average Rate Base		(I)	CC-PROPTAX
402	RATE CASE RESERVE	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASEMN
403	RESTRICTED STOCK	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
404	RETAIL RATE CASE EXPENSE	various		C-RATEBASE	X	X	X	Total Average Rate Base - Retail		(I)	CC-RATEBASEMN
405	RETIREMENTS	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
406	RSOP	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
407	SEC 162(M) LIMITATION	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
408	SECTION 174	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
409	TAX/BOOK DEPRECIATION DIFFERENCE	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
410	TAX CAPITALIZED INTEREST	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
411	TAX GAIN	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	C-EPIS
412	UNREALIZED BOOK LOSSES	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
413	BAD DEBT EXPESNE	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
414	EMPLOYEEE EXPENSE - NONDEDCUTIBLE	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
415	OFFICER COMP	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
416	**INCOME TAXES**										
417	STATE CURRENT INCOME TAX										
418	ADJUSTED TAXABLE INCOME	-		C-ADJNETINC	X	X	X	CCOSS CALCULATION		-	CC-ADJNETINC
419	STATE NOL UTILIZATION			C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
420	STATE DEPRECIATION MODIFICATION	-		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
421	STATE NET TAXABLE INCOME	-			X	X	X	CCOSS CALCULATION			
422	STATE TAX AT 9.8 PERCENT	-		C-STATETAX	X	X	X	CCOSS CALCULATION			CC-STATETAX
423	STATE TAX CREDITS	-		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
424	CORRECTION TO PRIOR YEARS			C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
425	STATE MINIMUM TAX			C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
426	FEDERAL CURRENT INCOME TAX										
427	FEDERAL TAXABLE INCOME	-		C-ADJNETINC	X	X	X	CCOSS CALCULATION		-	CC-ADJNETINC
428	STATE TAX DEDUCTION	-		C-STATEINCTAX	X	X	X	CCOSS CALCULATION			CC-STATEINCTAX
429	FEDERAL NOL UTILIZATION	-		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
430	FEDERAL NET TAXABLE INCOME	-			X	X	X	CCOSS CALCULATION		-	
431	FEDERAL TAX AT 21 PERCENT	-		C-FEDTAX	X	X	X	CCOSS CALCULATION			CC-FEDTAX
432	TAX CREDITS	-		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
433	CORRECTION TO PRIOR YEARS			C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
434	**PROVISION FOR DEFERRED INCOME TAX**										
435	ACCOUNT 410.1										
436	STEAM	410.1		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
437	HYDRO	410.1		C-HYDRO	X	X	-	Hydro PIS		(I)	CC-HYDRO
438	WIND	410.1		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
439	SOLAR	410.1		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
440	TRANSMISSION	410.1		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
441	DISTRIBUTION	410.1		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
442	GENERAL	410.1		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
443	**PROVISION FOR DEFERRED INCOME TAX - CREDIT**										
444	ACCOUNT 411.1										
445	STEAM	411.1		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
446	HYDRO	411.1		C-HYDRO	X	X	-	Hydro PIS		(I)	CC-HYDRO
447	WIND	411.1		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
448	SOLAR	411.1		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
449	TRANSMISSION	411.1		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
450	DISTRIBUTION	411.1		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
451	GENERAL	411.1		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
452	**INVESTMENT TAX CREDIT**										
453	ACCOUNT 411.4										
454	STEAM	411.4		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
455	HYDRO	411.4		C-HYDRO	X	X	-	Hydro PIS		(I)	CC-HYDRO
456	WIND	411.4		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
457	SOLAR	411.4		C-SOLAR	X	-	-	Solar PIS			CC-SOLAR

Table 5 Summary of Functionalization, Classification and Allocation in MP's CCOSS

Line	Functionalization and Classification of Rate Base and Income Statement Accounts 1/	FERC Account or MP's Plant Account or Function Code	Note	Name of Classification Allocator 11/	Classification Demand	Classification Energy	Classification Customer	Basis of Jurisdictional Cost Allocation	Basis of Retail Class Cost Allocation	Internal (I) or External (E) Allocator	Name of Customer Class Allocator 12/
458	TRANSMISSION	411.4		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
459	DISTRIBUTION	411.4		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
460	**ALLOWANCE FUNDS DURING CONSTRUCTION**										
461	STEAM	419.1, 432		C-STEAMCWIP	X	-	-	Total CWIP Steam		(I)	CC-STEAMCWIP
462	HYDRO	419.1, 432		C-HYDROCWIP	X	X	-	Total CWIP Hydro		(I)	CC-HYDROCWIP
463	WIND	419.1, 432		C-WINDCWIP	X	-	-	Total CWIP Wind		(I)	CC-WINDCWIP
464	SOLAR	419.1, 432		C-SOLARCWIP	X	-	-	Total CWIP Solar		(I)	CC-SOLARCWIP
465	TRANSMISSION	419.1, 432		C-TCWIP	X	-	-	Total CWIP Transmission		(I)	CC-TCWIP
466	DISTRIBUTION	419.1, 432		C-DCWIP	X	-	X	Total CWIP Distribution		(I)	CC-DCWIP
467	GENERAL	419.1, 432		C-OMLXAG	X	X	X	Total CWIP General Plant		(I)	CC-OMLXAG
468	INTANGIBLE PLANT	419.1, 432		C-OMLXAG	X	X	X	Total CWIP Intangible Plant		(I)	CC-OMLXAG

Notes:
1/ All items are generally presented in the same order as in MP's CCOSS.
2/ All regulated Hydro projects and assets at reservoir facilities only are subfunctionalized as production energy, remaining plant is demand.
3/ Step-up transformers at generating stations booked in transmission plant are subfuctionalized as production demand.
4/ Refer to MP's COSS Guide for description of treatment of distribution plant.
5/ Step-up transformers at generating stations booked in distribution plant are subfuctionalized as production demand.
6/ Distribution Bulk Delivery are 23, 34 and 46 kV facilities that serve FERC and retail jurisdictional customers.
7/ Specific Distribution 14 kV facilities and 23, 34, and 46 kV taps that serve FERC jurisdictional customers.
8/ Subfunctionalized to production, transmission and distribution on most recent calender year actual amounts. Distribution subsequently subfunctionalized/classifed on PIS ratios.
9/ Calculated
10/ Calculated as part of interest syncronization. Average rate base multiplied by cost of long term debt.
11/ Refer to Volume 3, Direct Schedules E-3, Part 5a, 5b, and Part 6a, 6B for the classifcation allocators, bases and factors.
12/ Refer to Volume 3, Direct Schedules E-3, Part 7a, 7b, 7c and Part 8a, 8b for the customer allocators, bases and factors.

Comparison of Minnesota Jurisdictional Factors

Line No.	Previous Allocation Code	New UI Allocation Code	Description	2024 Test Year Docket No. E015/GR-23-155	2025 Actual	2026 Projected	2027 Test Year Docket No. E015/GR-26-199
1	**Demand**			(1)	(2)	(3)	(4)
2	D01	CC-PROD	Power Supply Production	88.65%	87.82%	88.04%	82.95%
3	D02	CC-TRAN	Power Supply Transmission	82.59%	81.87%	82.13%	77.12%
4	D03	CC-DODBD	Distribution Bulk Delivery	71.69%	70.23%	66.17%	64.93%
5	D05	CC-DODSUB	Distribution Substations	100.00%	100.00%	100.00%	100.00%
6	D06	CC-DPOHL	Primary Overhead Lines	100.00%	100.00%	100.00%	100.00%
7	D07	CC-DPUGL	Primary Underground Lines	100.00%	100.00%	100.00%	100.00%
8	D10	CC-DSOHL	Secondary Overhead Lines	100.00%	100.00%	100.00%	100.00%
9	D11	CC-DSUGL	Secondary Underground Lines	100.00%	100.00%	100.00%	100.00%
10	D12	CC-DSOHT	Overhead Line Transformers	100.00%	100.00%	100.00%	100.00%
11	D13	CC-DSUGT	Underground Line Transformers	100.00%	100.00%	100.00%	100.00%
12	D14	CC-DSOHS	Overhead Services	100.00%	100.00%	100.00%	100.00%
13	D15	CC-DSUGS	Underground Services	100.00%	100.00%	100.00%	100.00%
14	**Energy**						
15	E01	CC-PROD	Power Supply Production	85.91%	83.44%	84.12%	80.62%
16	CIPEXPE	CC-CIP	Conservation Improvement Program Expense	100.00%	100.00%	100.00%	100.00%
17	**Customer**						
18	C01	CC-DPOHL	Primary Overhead Lines	100.00%	100.00%	100.00%	100.00%
19	C02	CC-DPUGL	Primary Underground Lines	100.00%	100.00%	100.00%	100.00%
20	C03	CC-DSOHL	Secondary Overhead Lines	100.00%	100.00%	100.00%	100.00%
21	C04	CC-DSUGL	Secondary Underground Lines	100.00%	100.00%	100.00%	100.00%
22	C05	CC-DSOHT	Overhead Line Transformers	100.00%	100.00%	100.00%	100.00%
23	C06	CC-DSUGT	Underground Line Transformers	100.00%	100.00%	100.00%	100.00%
24	C07	CC-DSOHS	Overhead Services	100.00%	100.00%	100.00%	100.00%
25	C08	CC-DSUGS	Underground Services	100.00%	100.00%	100.00%	100.00%
26	C09	CC-DSLEASED	Leased Property	100.00%	100.00%	100.00%	100.00%
27	C11	CC-DSMETERS	Meters	98.82%	99.02%	99.02%	99.02%
28	C12	CC-OMACCOUNT	Customer Accounts	99.32%	99.64%	99.63%	99.59%
29	C13	CC-OMSALES	Sales	100.00%	100.00%	100.00%	100.00%
30	C14	CC-OMSERVICE	Customer Service	99.74%	99.78%	99.78%	99.78%