Direct Testimony and Schedules
Stewart J. Shimmin

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-23-155

Exhibit ________

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

November 1, 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Stewart J. Shimmin, 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 Revenue Requirements Lead.

Q. Please summarize your qualifications and experience.

A. I have over 17 years of experience with Minnesota Power within the Rates Department. My responsibilities include supporting retail general rate cases and other financial regulatory filings, including cost recovery riders. I provide guidance and advice on Minnesota Power's class-cost-of-service model and on overall revenue requirement determination and analysis, as well as coordinating various Rates Department activities and projects.

I earned a Bachelor of Science in Economics from the University of Utah and a Master's Degree in International Management from the American Graduate School of International Management – Thunderbird. Prior to joining Minnesota Power, most of my career was in various positions in Indonesia. I provided specialty chemicals and services to multinational oil and gas companies throughout Indonesia for a Fortune 500 company. I was an Economist for a leading international engineering consulting firm where I carried out feasibility analyses of public sector infrastructure and rural and agricultural development projects financed by the World Bank and other international financing agencies. As a Financial Analyst, I carried out financial planning, capital budgeting, feasibility analyses, and economic and financial forecasting of private and public sector development projects—including toll roads, ports, and mass-transit systems. I also served as General Manager and Financial Controller at the Indonesian office of an international manpower supply company serving the mining and oil and gas industries in Indonesia.

Q. What is the purpose of your testimony?

A. I present Minnesota Power's 2024 Class Cost of Service Study ("CCOSS"). I address a compliance matter from Minnesota Power's 2021 Rate Case, Docket No. E015/GR-21-335 ("2021 Rate Case"). 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 provide a summary of minor changes and updates to the CCOSS since the 2021 Rate Case 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 a compliance matters from Minnesota Power's previous rate cases;
- Section III presents the results of the 2024 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 new rider.

Q. Are you sponsoring any exhibits in this proceeding?

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

- MP Exhibit ___ (Shimmin), Direct Schedule 1 – Guide to Minnesota Power's CCOSS;
- MP Exhibit ___ (Shimmin), Direct Schedule 2 – Comparison of Jurisdictional Allocation Factors; and
- MP Exhibit ___ (Shimmin), Direct Schedule 3 – Interim and Final Rate Increases Net of Riders.

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 prior rate cases. Specifically, I will address Order Point 37 of the Minnesota Public Utilities Commission's ("Commission") Order in the Company's 2021 Rate Case[1] that required Minnesota Power to allocate Advanced Metering Infrastructure ("AMI") metering costs as 1/3 energy-related, 1/3 demand-related, and 1/3 customer-related in its next rate case or propose another allocation method based on a study of these costs. I also address the requirement in Order Point 20 from Minnesota Power's 2009 Rate Case, Docket No. E015/GR-09-1151 ("2009 Rate Case") that 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.[2]

Q. Please discuss how the Company has complied with Commission Order Point 37 in the Company's 2021 Rate Case.

A. In compliance with the Order, the Company has classified AMI metering costs as 1/3 energy-related, 1/3 demand-related, and 1/3 customer-related as shown in the CCOSS classification allocator list in Volume 3, Direct Schedule E-3, Part 6b, page 1, line 23, C-METERS. The corresponding customer, demand, and energy class allocators are shown in the CCOSS customer class allocator list in Volume 3, Direct Schedule E-3, Part 8b, pages 3, 5, and 7, respectively, line 17, CC-DSMETERS.

Q. Please generally describe the calculation of the customer, demand, and energy CC-DSMETERS allocation factors.

A. The customer CC-DSMETERS allocation factors are calculated as described in MP Exhibit ___ (Shimmin), Direct Schedule 1 – Guide to Minnesota Power's CCOSS, pages 18–19. This is the same methodology as approved or affirmed by the Commission

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[1] *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 81 at Order Point 37 (Feb. 28, 2023).

[2] *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. 12, 2010).

in Minnesota Power's last four completed rate cases (Docket Nos. E015/GR-08-415, E015/GR-09-1151, E015/GR-16-664, and E015/GR-21-335), and in the Company's last Federal Energy Regulatory Commission ("FERC") wholesale rate case (FERC Docket No. ER08-397-000).

The demand CC-DSMETERS allocation factors are based on the CC-PROD – Demand allocator calculated as described in MP Exhibit ___ (Shimmin), Direct Schedule 1 – Guide to Minnesota Power's CCOSS, pages 9–12. This is the same methodology affirmed by the Commission in Minnesota Power's 2021 Rate Case.

The energy CC-DSMETERS allocation factors are based on the CC-PROD – Energy allocator calculated as described in MP Exhibit ___ (Shimmin), Direct Schedule 1 – Guide to Minnesota Power's CCOSS, pages 13–14. This is the same methodology as approved or affirmed by the Commission in Minnesota Power's last four completed rate cases (Docket Nos. E015/GR-08-415, E015/GR-09-1151, E015/GR-16-664, and E015/GR-21-335).

The demand and energy CC-DSMETERS allocators were normalized to equal the FERC jurisdictional customer CC-DSMETERS allocation to avoid misallocation to the FERC jurisdiction when the three allocators are applied in the CCOSS.

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

A. Yes. Order Point 20 required that Minnesota Power shall 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 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 Commission requirements.

III. CCOSS MODEL AND RESULTS

A. CCOSS Results

Q. Please provide an overview of the final allocation of revenue requirement to customer class for adjusted test year 2024 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 2024 CCOSS Required Revenue Increase by Customer Class Including Dual Fuel

Required Increase (Decrease)	$	%
Residential	$55,879,915	42.25%
General Service	$24,216,066	25.39%
Large Light & Power	$15,287,785	12.44%
Large Power	$31,974,014	8.20%
Lighting	$494,897	12.25%
Total	**$127,852,677**	**17.17%**

Q. Can you provide some context for these results?

A. Yes. The high increase for the Residential class is not an unexpected result. In Minnesota Power's 2016 Rate Case, Docket No. E015/GR-16-664 ("2016 Rate Case"), the final revenue apportionment approved by the Commission resulted in the Residential class being about 22 percent below its cost of service. In Minnesota Power's 2021 Rate Case, the final revenue apportionment approved by the Commission resulted in the Residential class being about 23 percent below its cost of service. As a result of this history, combined with the increase in the overall revenue deficiency since the Company's 2021 Rate Case, the Residential class is now even further away from its cost of service.

Further, as discussed below in Section VI of my testimony, customers are already paying for about $16.4 million of the total increase above in a separate cost recovery line item that is being rolled into base rates from the Transmission Cost Recovery Rider coincident with Interim Rates. Additionally, another $22.4 million of the increase above will be offset in the Renewable Resources Rider as also discussed below in Section VI. As such, nearly one-third of this increase pertains to costs transferred from rider recovery to base rates, rather than new costs to customers.

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. 2024 Adjusted Test Year Class Revenue Requirements by Classification Including Dual Fuel

Revenue Requirements	Total	Customer	Demand	Energy
Residential	$188,146,301	$43,942,538	$95,715,254	$48,488,509
General Service	$119,613,587	$9,166,466	$77,723,833	$32,723,288
Large Light & Power	$138,203,206	$886,306	$88,379,151	$48,937,749
Large Power	$422,109,287	$281,824	$248,691,142	$173,136,321
Lighting	$4,533,345	$3,295,399	$846,511	$391,435
Total	**$872,605,727**	**$57,572,532**	**$511,355,893**	**$303,677,302**

Table 3. 2024 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	$1	($0)	$1	$0	$0	$0
Demand	$332,791,041	$55,370,072	$38,766,561	$55,647,860	$182,507,278	$499,270
Energy	$300,176,883	$47,967,485	$32,372,713	$48,398,729	$171,050,664	$387,292
Subtotal Production	632,967,925	103,337,556	71,139,275	104,046,589	353,557,942	886,562
Transmission						
Demand	$110,514,963	$16,058,141	$12,449,374	$18,043,833	$63,865,935	$97,680
Energy	$0	$0	$0	$0	$0	$0
Subtotal Transmission	110,514,963	16,058,141	12,449,374	18,043,833	63,865,935	97,680
Distribution Bulk Delivery						
Demand	$14,729,261	$4,537,194	$5,755,153	$3,977,930	$398,256	$60,730
Subtotal Dist Bulk Delivery	14,729,261	4,537,194	5,755,153	3,977,930	398,256	60,730
Distribution Primary						
Customer	$14,769,050	$11,940,026	$2,233,830	$46,801	$0	$548,393
Demand	$35,433,319	$11,497,092	$14,572,268	$9,210,072	$0	$153,888
Subtotal Dist	50,202,369	23,437,117	16,806,098	9,256,873		702,281
Distribution Secondary						
Customer	$21,800,130	$15,648,008	$3,428,461	$73,781	$0	$2,649,879
Demand	$14,386,881	$7,670,343	$5,772,697	$914,142	$0	$29,699
Subtotal Dist Secondary	36,187,011	23,318,351	9,201,158	987,924		2,679,578
Meters						
Customer	$3,501,207	$2,683,577	$674,460	$43,694	$92,910	$6,566
Demand	$3,500,427	$582,413	$407,780	$585,315	$1,919,674	$5,244
Energy	$3,500,419	$521,024	$350,575	$539,019	$2,085,657	$4,143
Subtotal Meters	10,502,053	3,787,015	1,432,814	1,168,029	4,098,241	15,953
Customer Services						
Customer	$17,502,145	$13,670,927	$2,829,715	$722,029	$188,914	$90,560
Subtotal Customer Services	17,502,145	13,670,927	2,829,715	722,029	188,914	90,560
Total	**$872,605,727**	**$188,146,301**	**$119,613,587**	**$138,203,206**	**$422,109,287**	**$4,533,345**

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 by Company witness Ms. Leah N. Peterson.

Q. In your opinion, 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 Ms. Peterson.

Q. Did Minnesota Power generate and include other CCOSS results apart from the 2024 test year General Rates shown above?

A. Yes, a number of other CCOSS results were generated, including Interim Test Year 2024 CCOSS, Unadjusted Test Year 2024 CCOSS, Projected Fiscal Year 2023 CCOSS, and Most Recent Fiscal Year 2022 CCOSS. All of these CCOSS results are based on allocation methods previously approved, affirmed, or ordered by the Commission. 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 by Company witness Ms. Amanda L. Turner.

B. Classification and Cost Allocation Methodologies

Q. Does Minnesota Power's 2024 CCOSS use the same classification and allocation methodologies affirmed or ordered by the Commission in Minnesota Power's 2021 Rate Case?

A. Yes. Apart from implementing the change to the classification and allocation of AMI metering costs to comply with the Commission's Order in Minnesota Power's 2021 Rate Case as discussed above, the CCOSS in the present filing uses the same classification and allocation methodologies as the Company's CCOSS in its 2021 Rate Case. In Minnesota Power's 2021 Rate Case, the Commission concurred with the Administrative Law Judge's findings and affirmed the Company's classification and allocation of fixed production costs[3] and transmission costs.[4] Additionally, the

[3] *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). Fixed production costs were classified as 100 percent demand and allocated to class on the 4CP Average & Excess method.
[4] *Id.* at 57. Transmission costs were classified as 100 percent demand and allocated on the 12CP method.

Commission concurred with the Administrative Law Judge'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.[5] Lastly, the Commission concurred with the Administrative Law Judge that the Company's E8760 allocator remains the best method for allocating energy costs.[6] As discussed further below, the Company has updated the E8760 allocator with recent data acquired from the full deployment of the Company's AMI technology. These methods are discussed further below in Section V of my testimony.

C. Refinements to the CCOSS

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

A. In this section, I identify refinements to the CCOSS the Company implemented to facilitate review by simplifying presentation of reporting lines, reduce redundancies, and increase efficiency in running the CCOSS. These changes are limited in nature and are not changes to either the Company's classification or allocation methods. I walk through the rate base and operating income reporting line refinements below.

Q. What changes were made to the CCOSS reporting lines for rate base?

A. The reporting line Distribution Other – Distribution Bulk Delivery Specific Assignment (FERC) was split into respective components Distribution Substations Specific Assignment (FERC) and Distribution Bulk Delivery Specific Assignment (FERC).

All sub-functional reporting lines for Distribution under Accumulated Depreciation were condensed, and Amortization of Intangible Plant was moved up and included under the new sub-total for Accumulated Depreciation and Amortization. The detailed functionalization, classification, and allocations of these items still exist within the underlying calculations.

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[5] *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.
[6] *Id.* at 63.

The sub-functional reporting lines under Materials and Supplies, Prepayments, Other Additions and Deductions to Rate Base, Accumulated Deferred Income Taxes Credits, and Accumulated Deferred Income Taxes Debits were all reformatted to simply remove blank reporting lines.

The above changes significantly reduced the number of rate base reporting lines.

Q. What changes were made to the CCOSS reporting lines for operating income?

A. Other Operating Revenue (OOR) was re-formatted to eliminate blank reporting lines and condense the three Distribution sub-functional reporting lines. Operation and Maintenance Expense, Taxes Other than Income Taxes, Deferred Income Taxes, and Investment Tax Credits were similarly re-formatted to eliminate blank reporting lines where possible. Lastly, the sub-functional reporting line under Allowance for Funds Used During Construction was condensed into a single reporting line. As with the refinements to the rate base reporting lines, the detailed functionalization, classification, and allocations of these items still exist within the underlying calculations.

The above changes significantly reduced the number of operating income reporting lines.

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 Transformer
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, hydraulic, wind, and solar generating facilities. The transmission function includes the costs associated with 69 kilovolt ("kV") and above transmission lines and substations. Distribution plant 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 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 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 hydraulic 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 and demand. 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 in 2022. As further described in MP Exhibit ___ (Shimmin), Direct Schedule 1 attached to my testimony, the study was based on page 87 of the NARUC 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 4, and the Distribution Plant Study is included in Volume 4, Workpapers, OS-1.

Table 4. Classification of Distribution Plant

Based on 2022 Distribution Plant Study

Plant	FERC Account / *Function Code*	Function	Customer Classification Minimum System %	Demand Classification %
Poles , Towers	364, 365	Primary Overhead Lines	44.95%	55.05%
OH Conductors	*D300*	Secondary Overhead Lines	43.87%	56.13%
UG Conduits, &	366, 367	Primary Underground Lines	34.94%	65.06%
Conductors	*D400*	Secondary Underground Lines	10.12%	89.88%
Line	368	Overhead Transformers	55.00%	45.00%
Transformers	*D500*	Underground Transformers	94.84%	5.16%
Services	3691	Overhead Services	65.42%	34.58%
	3692	Underground Services	31.88%	68.12%
	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 4 in the "Guide to Minnesota Power's CCOSS" attached to my Direct Testimony as MP Exhibit ___ (Shimmin), 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 four completed rate cases before the Commission (Docket Nos. E015/GR-08-415, E015/GR-09-1151, E015/GR-16-664, and E015/GR-21-335) 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 12 Coincident Peak ("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 2022, the jurisdictional separation of costs assigned to Customer Accounting and Customer Service and Information are 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 2023 projected year and the 2024 test year use the same actual allocation ratios as 2022 for customer costs?

A. Yes, the 2023 projected year and the 2024 test year budgeted amounts were allocated using the 2022 ratios to determine 2023 and 2024 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 four retail rate cases (Docket Nos. E-015/GR-08-415, E-015/GR-09-1151, E015/GR-16-664, and E015/GR-21-335) and Minnesota Power'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 2021 Rate Case?

A. The comparison of the jurisdictional allocation factors is shown in MP Exhibit ___ (Shimmin), Direct Schedule 2 attached to my testimony. As discussed above, the jurisdictional allocation methods are the same as used in the Company's last four 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 Schedule 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 2022, Unadjusted Projected Fiscal Year 2023, and Proposed Test Year 2024;
- Schedule B-18 provides the Minnesota Jurisdiction allocator bases by classification for the Unadjusted Most Recent Fiscal Year 2022, Unadjusted Projected Fiscal Year 2023, and Proposed Test Year 2024;

- Schedule B-19 provides the Minnesota Jurisdiction allocator factors by classification for the Unadjusted Most Recent Fiscal Year 2022, Unadjusted Projected Fiscal Year 2023, and Proposed Test Year 2024;
- Schedule C-13 lists the Operating Income components by CCOSS reporting line and provides the jurisdictional allocator names/codes for 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 ___ (Shimmin), Direct Schedule 1.

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

A. Yes—as the comparison covers a three-year period, there have been changes in Minnesota Power's operations, which have slightly impacted the jurisdictional allocations since our 2021 Rate Case. Generally, the minor changes seen in demand and energy allocators from the previous 2022 test year through the current 2024 test year reflect a combination of partially offsetting changes between Minnesota Power's non-retail or FERC load relative to the Company's retail load: 1) Both ST Paper, a retail customer, and Cenovus, a customer of the Company's FERC subsidiary Superior Water Light & Power, were not operational in 2022 although their full load was included in the final 2022 test year; 2) in September 2022 Hibbing Public Utilities ceased being a full requirement FERC municipal customer of Minnesota Power; 3) the 2023 allocators reflect the start-up of ST Paper and return to full operations of Cenovus by mid-year, as well as the full year impact of the loss of Hibbing Public Utilities; and 4) the current 2024 test year reflects slightly overall reduced total sales compared to the previous 2022 test year, with the reduction in FERC sales being relatively larger than the reduction in retail sales, primarily due to the loss of Hibbing Public Utilities. Overall, the Minnesota jurisdictional customer-related allocators are very similar or flat compared to the previous 2022 test year.

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 ___ (Shimmin), 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 AMI meter costs to comply with the Commission's Order from the 2021 Rate Case as discussed above, the CCOSS in the present filing uses the same classification and allocation methodologies. Fixed production costs are classified as 100 percent demand and allocated to class on the 4

Coincident Peak ("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 ___ (Shimmin), Direct Schedule 1, Guide to Minnesota Power's CCOSS, 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 into the CCOSS.

(a) <u>Demand allocation factors analyses</u> — 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 2022, as well as from the projected year and test year budgeted demands. As anticipated and communicated in the Company's 2021 Rate Case, the 2022 actual load data has now been acquired from the full deployment of the Company's AMI technology. This actual hourly data was used to scale the budgeted 2023 and 2024 loads. Therefore, beginning with this case and going forward, 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 ___ (Shimmin), Direct Schedule 1, Guide to Minnesota Power's CCOSS, and to Volume 4, Workpapers, AF for further details.

(b) <u>Energy allocation factors analyses</u> — Analyses of energy usage were carried out by jurisdiction, by customer class, and in some cases, by customer. Similar to the demand allocation factor analyses, the energy analyses were based on the most recently available historical load data from 2022, as well as from the projected year and test year budgeted demands. As anticipated and communicated in the Company's 2021 Rate Case, the 2022 actual energy data has now been acquired from the full deployment of the Company's AMI technology. This actual hourly data was used to scale the budgeted 2023 and 2024 loads. For the last several Minnesota Power rate cases, the Company 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 ___ (Shimmin), Direct Schedule 1, Guide to Minnesota Power's CCOSS, 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 2022, budgeted data for 2023, as well as from 2024 test year projected numbers of customers. Refer to MP Exhibit ___ (Shimmin), Direct Schedule 1, Guide to Minnesota Power's CCOSS, and to Volume 4, Workpapers, AF.

(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 2022 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 2021 data. The report is included in Volume 4, Workpapers, OS-2.

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

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 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 identify the Company's proposed plan for addressing its current riders going forward, and discuss the proposed Rider for Capacity Revenue and Expenses Adjustment ("CRE").

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:

- Rider for Transmission Cost Recovery ("TCR");
- Rider for Renewable Resources ("RRR");
- Rider for Renewable Resources – Solar Factor Adjustment ("SRRR"); and
- Rider for Fuel and Purchased Energy ("FPE") Charge (discussed by Company witness Ms. Peterson).

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

Q. Are there any Order Points from the Company's 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:

> [i]n 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, 2023. The costs for projects that are currently being recovered through riders that will not be completed by December 31, 2023, 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 5 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 122 at Order Point 47 (March 12, 2018).

Table 5. Summary of Rider Treatment in 2024 Test Year

TCR Rider	
Moving to Base Rates	**Staying in the Rider**
Great Northern Transmission Line ("GNTL") Project	Duluth Loop Project (new)
	Regional Expansion Criteria and Benefits ("RECB") Net Expense/Revenue and Credit for Midcontinent Independent System Operator ("MISO") Multi-Value Projects Revenue
Renewable Resources Rider (RRR)	
Moving to Base Rates	**Staying in the Rider**
Reset PTC to 2024 budgeted level	Production Tax Credit True-up
Solar Factor (under RRR)	
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. What revenues and expenses does Minnesota Power propose to continue to include in the TCR Rider?

A. Minnesota Power proposes to continue to use the TCR Rider to recover costs for the following: (1) the Duluth Loop Project; (2) RECB net revenue and expenses; and (3) MISO transmission facility net revenues or expenses. The Duluth Loop Project was included for the first time in its recently submitted 2024 TCR filing.[9]

[9] *In the Matter of Minn. Power's Petition for Approval of a Transmission Cost Recovery Rider under Minn. Stat. § 216B.16, subd. 7b*, Docket E015/M-23-460, Petition for Approval (Oct. 24, 2023).

Q. Why does the Company propose to include the Duluth Loop Project in the TCR Rider?

A. This project will not be in-service for a couple more years. The Company anticipates it will move this project into base rates in a future rate case, after the project is in-service.

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

A. The MISO transmission facility net revenues and expenses relate to the costs of MISO Transmission Expansion Planning projects and MISO Auction Revenue Rights ("ARR") revenues for the Multi-Value Projects ("MVP") 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 considers it appropriate to continue providing the net credit in the TCR Rider.

Q. Why does Minnesota Power propose to roll the GNTL Project into base rates?

A. As the Company was preparing to file its 2021 Rate Case, the GNTL Project, which was placed into service on June 1, 2020, was being considered by the Commission in the 2021 TCR Factor Filing (Docket No. E015/M-20-900) and there was still a relatively large TCR Rider tracker balance at the time. As anticipated in the 2021 Rate Case, it is now appropriate to roll GNTL into base rates at the beginning of this rate case, effective with implementation of Interim Rates. The Company recently filed its 2024 TCR Factor Filing excluding GNTL from the TCR Rider while requesting provisional approval to implement the new, much lower 2024 TCR billing factors coincident with Interim Rates in this case.[10]

[10] *Id.*

Q. Briefly describe the impact of moving the GNTL Project out of the TCR Rider and rolling the GNTL Project into base rates.

A. Customers will see a decrease in the TCR line item on their bills and an approximately equal increase in Interim Rates. The revenue requirements for the GNTL Project moving from the TCR Rider to base rates equate to about $16.4 million MN Jurisdictional based on the current TCR jurisdictional allocator and rate of return. Therefore, approximately 16 percent[11] of the Company's Interim Rate revenue requirement increase is simply a shift from TCR Rider recovery to base rate recovery for the GNTL Project. This is also equivalent to about 13 percent[12] of the Company's requested General Rate revenue requirement increase. Additionally, approximately $613,000 MN Jurisdictional in GNTL revenue requirements related to capitalized internal costs that, under Commission precedent, are typically excluded from rider recovery are now being included in base rates.

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

A. Minnesota Power proposes continued use of the RRR for one item in 2024. Specifically, 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 production tax credits ("PTCs") generated by the Bison Wind Projects that are currently in base rates. This true-up now also includes the PTCs generated by the Company's Taconite Ridge wind 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 2024 test year budgeted amount, and the new level will be used going forward with the true-up calculation in the RRR. Company witness Ms. Rena Verdoljak discusses the proposed test year PTC level in her Direct Testimony.

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[11] ($16.4 million / $102.6 million) = 16 percent.
[12] ($16.4 million / $127.9 million) = 13 percent.

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 2024 budgeted PTCs increases the base rate revenue requirements by about $22.4 million MN Jurisdictional. This represents approximately 22 percent[13] of the Company's Interim Rate revenue requirement increase and about 18 percent[14] of the Company's requested General Rate revenue requirement increase. However, beginning with Interim Rates, the new base rate PTC level will be credited to customers going forward in the true-up calculations in the RRR. Assuming actuals PTCs come in at the budgeted level, this means the monthly true-up in the RRR will be zero. Thus, a RRR credit (reduction) to customer bills will not occur until about October 2024, which is when customers will have paid for carryover PTC amounts from 2023 in the RRR and the updated billing factors are expected to go to near zero.

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

A. Please refer to MP Exhibit ___ (Shimmin) Direct Schedule 3 for a summary of the Interim and Final Rate increases net of riders. As shown on Direct Schedule 3, page 1, offsets in the TCR and RRR result in an Interim Rate net bill impact of about 8.6 percent. Similarly, offsets in the TCR and RRR result in a Final Rate net bill impact of about 12 percent. Direct Schedule 3, page 2 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 2024 budgeted PTC level in this case. Direct Schedule 3, page 3 shows the estimated revenue requirements of moving GNTL Project costs from the TCR to base rates.

Q. What does Minnesota Power propose with respect to the Solar Renewable Resources Rider ("SRRR")?

A. In the April 20, 2021 Order in the Company's 2020 Solar Renewable Factor (Docket E-015/M-20-557), the Commission approved the implementation of billing factors to

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[13] ($22.4 million / $102.6 million) = 22 percent.
[14] ($22.4 million / $127.9 million) = 18 percent.

recover the costs related to Minnesota Power's Camp Ripley Solar project, Community Solar Garden projects, and SolarSense program.[15] The Solar Renewable Factor was approved to appropriately allocate and recover costs to customers as set out in Minnesota's Solar Energy Standard ("SES"). 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 2024 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 2024 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 2024 test year. These adjustments are discussed by Company witness Ms. Turner and are shown in Volume 3, Schedules B-6 and C-10 for Total Company and in Volume 3, Schedule B-5 and Schedule C-9 for Minnesota Jurisdiction. Details are also shown in Volume 4, Workpapers, ADJ-RB-10 and ADJ-IS-23.

Q. Please describe the Company's proposed new CRE Rider.

A. In Minnesota Power's Resolution to the 2019 Rate Case, Docket E-015/M-20-429, the Commission approved moving energy and capacity sale revenue credits from base rates to the FPE Rider while leaving capacity purchase expense recovery in base rates. The Company is now proposing to remove both the energy and capacity revenue credits from the FPE Rider and the short-term (three years or less) capacity expense from base rates and recover the net of both in the new CRE Rider. This will align the revenue credits and near-term expense and create a more symmetrical recovery treatment. The details of this proposal, including the applicable sales revenues and purchase expense proposed to be included in the new rider, are discussed by Company witness Ms. Julie I. Pierce in her Direct Testimony. Additionally, Company witness Ms. Peterson

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[15] *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).

discusses the proposed tariff to be added to the Company's Electric Rate Book. The operating income adjustments to effectuate the removal of the capacity revenues and expenses from the CCOSS are explained by Company witness Ms. Turner in her Direct Testimony and are shown in Volume 3, Direct Schedules C-9 and C-10. The detailed support for the adjustments is shown in Volume 4, Workpapers, ADJ-IS-29. Lastly, the proposed new CRE Rider Adjustment line item can be seen in Direct Schedule E-1, page 2, in the Adjustment to Riders section.

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

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

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DESCRIPTION OF EXTERNALLY DEVELOPED ALLOCATION FACTORS

I. INTRODUCTION

This guide discusses the functionalization, classification, and allocation methodologies used by Minnesota Power 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 4) 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 FERC account, plant account, or Minnesota Power function code. Table 4 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 E015/GR-21-355 ("2021 Rate Case"). In compliance with Order Point 37 of the Commission Order in the 2021 Rate Case, the Company has allocated metering costs as 1/3 energy-related, 1/3 demand-related, and 1/3 customer-related[1]. This is discussed in Direct Testimony of Company witness Mr. Shimmin and is reflected in the descriptions below. Minor refinements since the last rate case are also discussed in Direct Testimony of Company witness Mr. Shimmin and are reflected in the descriptions below.

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.

[1] [1] *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 81 at Order Point 37 (February 28, 2023).

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, Part 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, Part 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 factor are as also shown together with the external allocators described and identified above.

The externally-developed and internally developed allocator are also identified in Table 4.

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 Proposed Test Year.

B. Steam Plant: FERC Accounts 310-317

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

This assignment is consistent with Minnesota Power's last four retail rate cases (Docket Nos. E015/GR-08-415, E015/GR-09-1151, E015/GR-16-664 and E015/GR-21-355) and was affirmed by the Commission in the Company 2021 Rate Case[2]. 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% demand if no direct assignment or exclusive use cost are 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 twelve 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 four retail rate cases as well is 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:

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

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.

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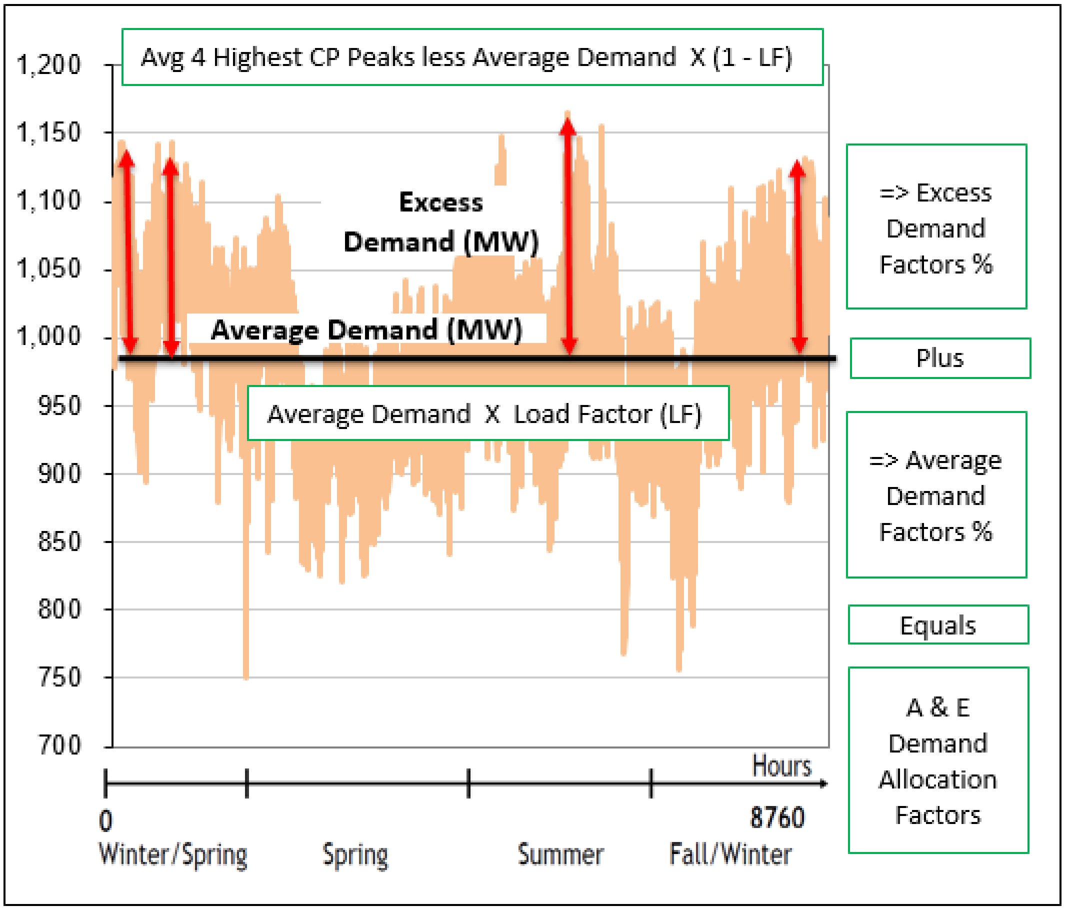
[2] Ibid at 55.

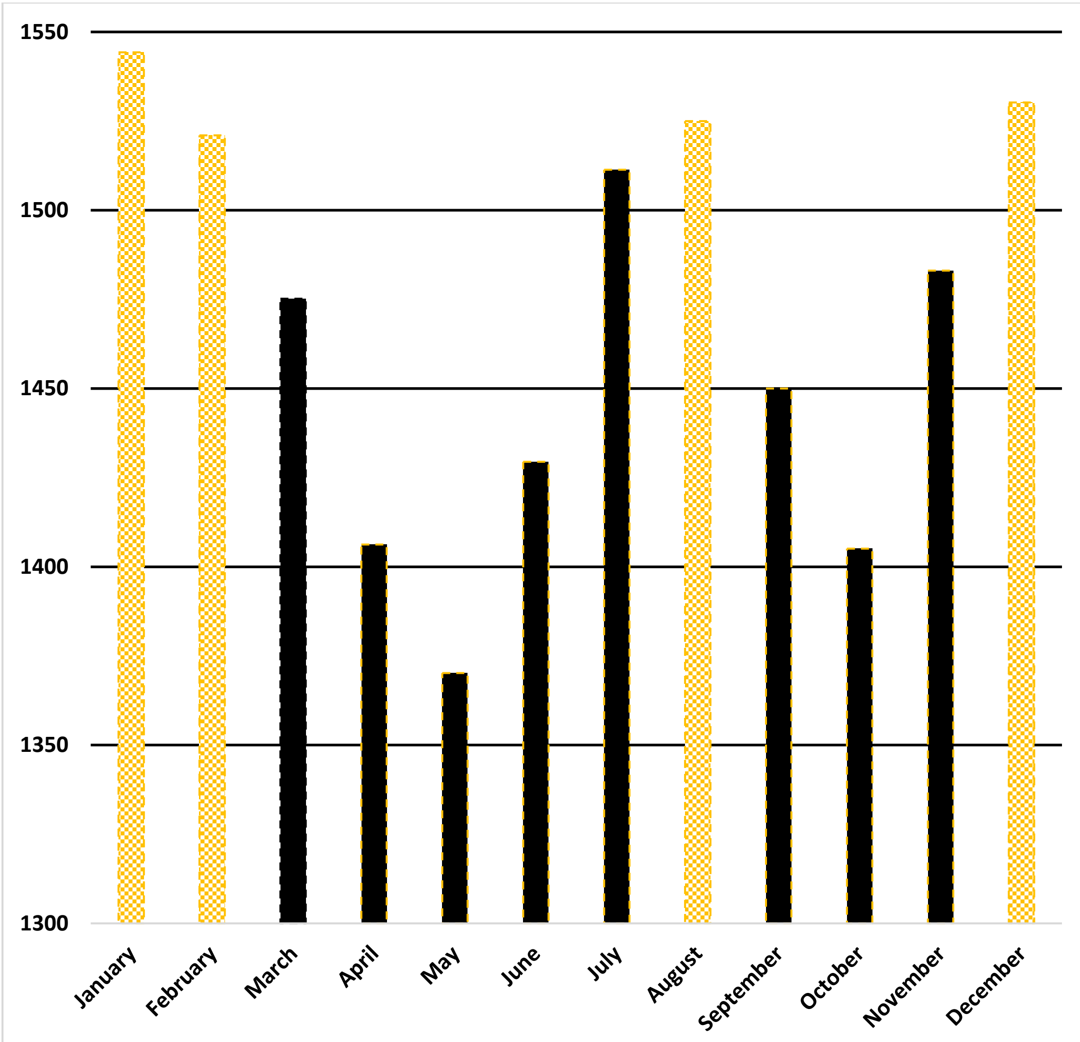
Figure 1: 4CP A&E Methodology



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 are allocated 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 three winter peaks and one summer in the allocation methodology, therefore, reflect cost causation. Figure 2 below shows Minnesota Power's historic average system peaks by month in yellow.

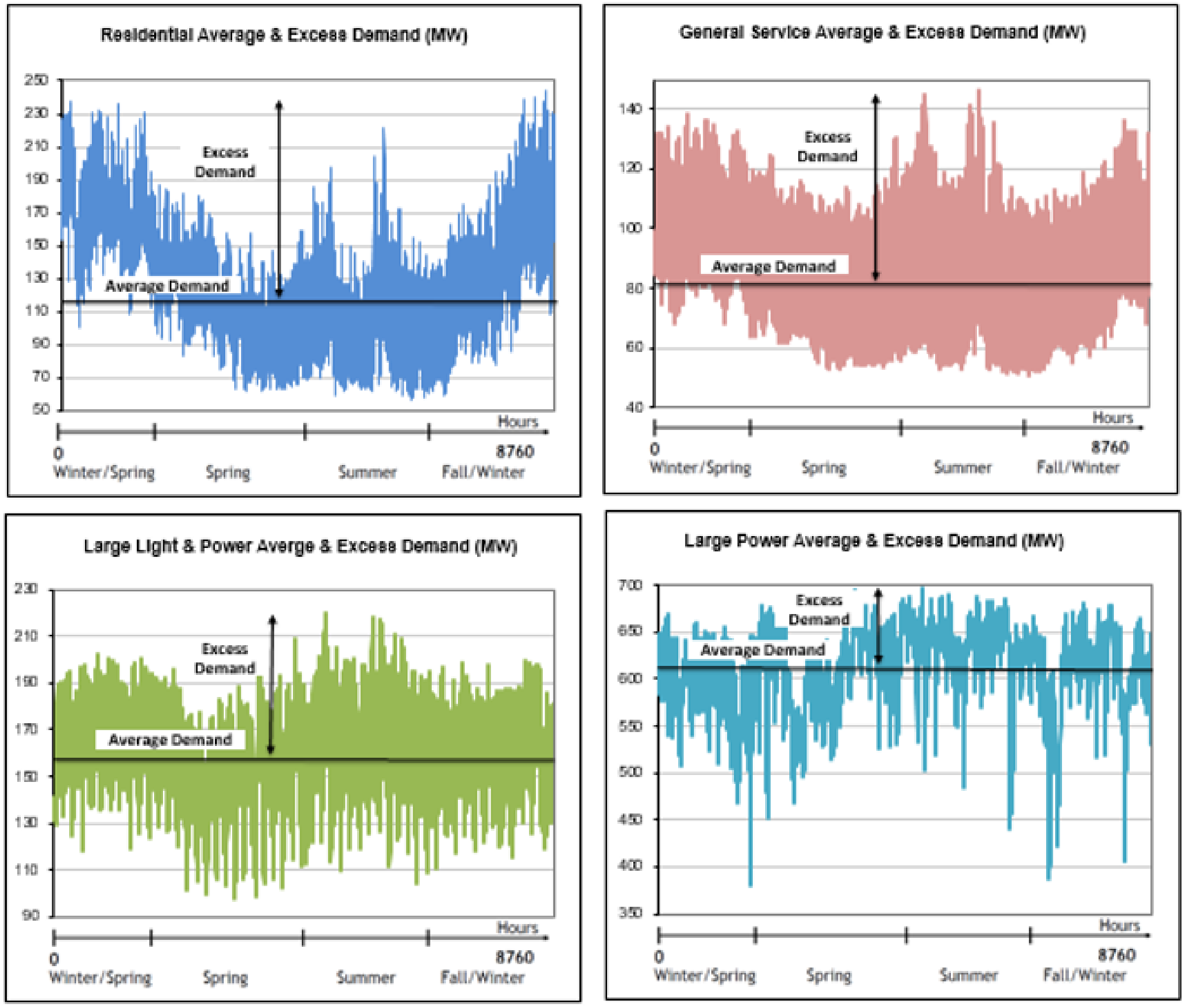
Figure 2: Minnesota Power's Four Highest Average System Peaks 2010-2022 Megawatt ("MW")



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 fours 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



In Minnesota Power's 2021 Rate Case, the Commission concurred with the Administrative Law Judge findings and affirmed the Company's classification and allocation of fixed production costs using the 4CP A&E methodology.[3]

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.

[3] Ibid at 55.

This method is consistent with Minnesota Power's last four retail rate cases, Minnesota Power's last FERC 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 four 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 classes 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, 12CP method for jurisdictional allocation and 4CP A&E method for retail class allocations.

This treatment of wind plant was approved in Minnesota Power's last four 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, 12CP method for jurisdictional allocation and 4CP A&E method for retail class allocations.

As discussed in Direct Testimony of witness Mr. Shimmin, 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 two rate case.

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 Transmission function.

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 12-month average coincident peak (12CP) method. The 12CP method aligns with cost allocations to the Company's FERC Municipal customers and with how most of MISO's transmission costs are incurred by the Company. This allocator has been approved and used for decades for Minnesota Power's jurisdictional allocation. In Minnesota Power's 2021 Rate Case, the Commission concurred with the Administrative Law Judge findings and affirmed the Company's classification and allocation of transmission costs using the 12CP methodology[4].

[4] Ibid at 57.

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 1 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 1. 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 four 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 four 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 – future EV Charger plant will be classified as demand and customer following the D300 and D400 above.

The above classifications are consistent with Minnesota Power's last four 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 2022 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 2 below summarizes customer and demand classification ratio results of the Distribution Plant Study. For more details, refer to the 2022 Distribution Plant Study in Volume 4, Workpapers.

D660 Distribution – Customer Premises – EV Charger is a new line item that will hold a new EV Charger project. All costs related to EV Charger project are excluded from the Test Year CCOSS because the project has been delayed and has not been submitted for Commission approval for cost recovery.

Table 2
Based on 2022 Distribution Plant Study

Plant	FERC Account / *Function Code*	Function	Customer Classification Minimum System %	Demand Classification %
Poles , Towers	364, 365	Primary Overhead Lines	44.95%	55.05%
OH Conductors	*D300*	Secondary Overhead Lines	43.87%	56.13%
UG Conduits, &	366, 367	Primary Underground Lines	34.94%	65.06%
Conductors	*D400*	Secondary Underground Lines	10.12%	89.88%
Line	368	Overhead Transformers	55.00%	45.00%
Transformers	*D500*	Underground Transformers	94.84%	5.16%
Services	3691	Overhead Services	65.42%	34.58%
	3692	Underground Services	31.88%	68.12%
	D600			

Customer, Demand and Energy Related

D650 Distribution – In compliance with Order Point 37 of the Commission Order in the 2021 Rate Case, the Company has classified and allocated metering costs as 1/3 customer-related, 1/3 demand-related, and 1/3 energy-related[5].

Customer Related

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 four retail rate cases and are also consistent with the NARUC Manual's classification (Chapter 6, page 96).

Allocation of Distribution Plant - *Jurisdictional*

Table 3 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.

[5] Ibid at 37.

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 3. 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	P & A	-
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.
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).

As discussed above, the Company has classified and allocated metering costs as 1/3 customer-related, 1/3 demand-related, and 1/3 energy-related in compliance with Order Point 37 of the Commission Order in the 2021 Rate Case. The demand CC-DSMETERS allocation factors are based on the CC-PROD – Demand allocator calculated as described above and the energy CC-DSMETERS allocation factors are based on the CC-PROD – Energy allocator calculated as also described above. The CC-PROD - Demand and CC-PROD – Energy are the same methodologies as affirmed by the Commission in Minnesota Power's last rate case (GR-21-355). For meters, the demand and energy CC-DSMETERS allocators were normalized to equal the FERC jurisdictional customer CC-DSMETERS allocation discussed above to avoid misallocation to the FERC jurisdiction when the three allocators are applied in the CCOSS.

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 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 a 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 NPC 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 the Table 3 above, distribution facilities are allocated to retail classes based on how they are classified – that is, either with demand allocation factors (CC-DODBD thru CC-DSUGS) or customer allocation factors (CC-DPOHL thru 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. As discussed above, Meter costs are allocated to class using the customer, demand, and energy 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 as 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 four rate cases, as well as with our last FERC 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 all jurisdictional and class allocators are detailed in Volume 4, Workpapers, under Allocation Factors ("AF").

H. <u>General Plant: FERC Accounts 389-399</u>

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 four 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: 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 four retail rate cases and Minnesota Power's last FERC rate case.

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 four retail rate cases and Minnesota Power's last FERC 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 four retail rate cases and Minnesota Power's last FERC 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 four retail rate cases, Minnesota Power's last FERC 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 four retail rate cases and Minnesota Power's last FERC rate case.

Prepayments (FERC account 16500, 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 four retail rate cases and Minnesota Power's last FERC rate case.

Prepayment – Pension Asset (FERC account 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 four retail rate cases for other labor related A&G costs and consistent with the methodology approved in Minnesota Power's last FERC rate case. This method is also discussed in the NARUC Manual (Chapter 8, page 106).

Prepayment – Silver Bay Power Corporation (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 two rate case.

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 four retail rate cases and Minnesota Power's last FERC 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 Account 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 E-015/GR-08/415).

O. Electric Vehicle Program: FERC Account 18640.0553

Deferred costs for Electric Vehicle Program which are excluded from Interim and General Rates pending request for recovery in a subsequent rate case.

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 four retail rate cases for other labor-related A&G costs and is consistent with the methodology approved in Minnesota Power's last FERC 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% per year and unamortized cost 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 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 Account 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 four retail rate cases and Minnesota Power's last FERC rate case.

IV. INCOME STATEMENT

A. Summary of Approaches and Assumptions

Refer to Volume 3, Direct Schedule 3, Summary of Approaches and Assumptions Used in Determining Operating Income for the 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 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, Silver Bay Power Corporation ("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 four 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 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.

Specific Retail – Distribution is then sub-functionalized and classified following distribution plant ratios.

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

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 Ms. 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 four retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC 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 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 three retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC 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 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

Wind O&M expenses are classified to demand consistent with the approach approved in Minnesota Power's two retail rate case 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 Production – Demand function (CC-PROD).

K. 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 four retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC 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 AFUDC contra. This composite allocator was used in the Company's 2021 Rate Case.

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

O&M expenses – Distribution – Meters are classified as 1/3 customer-related, 1/3 demand-related and 1/3 energy-related as discussed above.

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

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

In Minnesota Power's last three rate case, Distribution O&M Expenses were previously manually split between Meters, Distribution Bulk Delivery and Distribution Other. With the implementation of the UIP in the 2021 Rate Case, this split is directly mapped to Meters and Other Distribution, which includes Distribution Bulk Delivery.

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

N. 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 four retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC 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 Production – Demand function (CC-PROD).

O. 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 four retail rate cases and consistent with the methodology and that approved in Minnesota Power's last FERC 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 Production – Demand function (CC-PROD).

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

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

O&M expenses – Fuel is classified to 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 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).

Q. 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 four retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC 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.

R. 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 four retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC 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 V, Workpapers under Allocation Factors.

S. Operation & Maintenance Expense – Conservation Improvement Program: FERC Sub-Account 90806.0000

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

In the 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 MWh of energy subject to the CCRC.

T. 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 four retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC 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.

U. <u>Operation & Maintenance Expense – Property Insurance: FERC Account 924</u>

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

V. <u>Operation & Maintenance Expense – Regulatory Expenses – Misc.: FERC Account 928</u>

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

W. <u>Operation & Maintenance Expense – Regulatory Expenses – MISO: FERC Account 928</u>

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

X. <u>Operation & Maintenance Expense – Advertising: FERC Account 930.1</u>

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

Y. <u>Operation & Maintenance Expense – Franchise Requirements: FERC Account 927</u>

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

Z. <u>Operation & Maintenance Expense – Other A&G: FERC Accounts 920-921, 923, 925, 926, 930.2</u>

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

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

O&M Expenses – Donations 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 four retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC rate case.

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

CC. 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 four retail rate cases and Minnesota Power's last FERC rate case.

DD. Intangible Plant Amortization Expense: FERC Account 404

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

EE. 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.

FF. ARO Accretion Expense: FERC Account 411.1

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

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

Boswell 1 & 2 amortization ARO accretion 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.

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

II. 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 four retail rate cases and are consistent with the methodology approved in Minnesota Power's last FERC rate case.

JJ. Payroll Taxes: FERC Account 408.1

Payroll taxes for 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 four retail rate cases and are consistent with the methodology approved in Minnesota Power's last FERC rate case.

KK. 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 four retail rate cases.

LL. 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 four retail rate cases and are consistent with the methodology approved in Minnesota Power's last FERC 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 four retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC rate case.

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

NN. Federal Current Income Tax

Minnesota state tax 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% 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.

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

Provision for Deferred Income Tax are 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 four retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC rate case.

PP. Investment Tax Credit: FERC Account 411.4

Investment tax credits are 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 four retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC rate case.

QQ. <u>Allowance for Funds Used During Construction: FERC Accounts 419.1, 432</u>

Allowance for Funds Used During Construction ("AFUDC") are 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 four retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC rate case.

RR. <u>Operation & Maintenance Expense – Labor Only</u>

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 four retail rate cases and is consistent with the methodology approved in Minnesota Power's last FERC 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.

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Table 4 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/
	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-DSLEASED	-	-	X	-	Direct	(E)	CC-DSLEASED
39	STREET LIGHTING	373		C-DSLIGHTING	-	-	X	-	Direct	(E)	CD-DSLIGHTING
40	DISTRIBUTION OTHER										
41	METERS	370		C-DSMETERS	X	X	X	Juris Meters	1/3 D,1/3 E, 1/3 C	(E)/(I)	CC-DSMETERS
42	PRODUCTION - DEMAND	D200	5/	C-DOPROD	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
43	DISTRIBUTION BULK DELIVERY	D223, D234, D246	6/	C-DODBD	X	-	-	NCP	Class NCP	(E)	CC-DODBD
44	DISTRIBUTION SUBSTATIONS	D100		C-DODSUB	X	-	-	-	Class NCP	(E)	CC-DODSUB
45	DIST BULK DEL SPECIFIC ASSIGN	various	7/	C-DSA	X	-	-	Direct	-	(E)	CC-DSA
46	DIST PRIMARY SPECIFIC ASSIGN	various		C-DSA	X	-	-	Direct	-	(E)	CC-DSA
	DISTRIBUTION SUBSTATIONS SPEC AASIGN			C-DSA	X	-	-	Direct	-	(E)	CC-DSA
47	DISTRIBUTION CONTRA			C-DPPIS	X	-	X	Direct	-	(I)	CC-DPPIS

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48	GENERAL PLANT										
49	GENERAL PLANT	389-399		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
50	GENERAL PLANT CONTRA	389-399		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
51	INTANGIBLE PLANT										
52	INTANGILBE PLANT	301-303		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	C-OMLXAG
53	**CONSTRUCTION WORK IN PROGRESS**										
54	STEAM										
55	PRODUCTION - DEMAND	107		C-STEAMCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
56	STEAM CONTRA			C-STEAMCWIP	X	-	-	Direct	-	(I)	CC-STEAMCWIP-C
57	HYDRO										
58	PRODUCTION - DEMAND	107		C-HYDROCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
59	PRODUCTION - ENERGY	107		C-HYDROCWIP	-	X	-	E-01	E8760	(E)	CC-PROD
60	HYDRO CONTRA - DEMAND			C-HYDROCWIP	X	-	-	Direct	-	(I)	CC-HYDROCWIP-C
61	HYDRO CONTRA - ENERGY			C-HYDROCWIP	-	X	-	Direct	-	(I)	CC-HYDROCWIP-C
62	WIND										
63	PRODUCTION - DEMAND	107		C-WINDCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
64	WIND CONTRA			C-WINDCWIP	X	-	-	Direct	-	(I)	CC-WINDCWIP-C
65	SOLAR										
66	PRODUCTION - DEMAND	107		C-SOLARCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
67	TRANSMISSION										
68	TRANSMISSION PRODUCTION	107		C-TCWIP	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
69	TRANSMISSION	107		C-TCWIP	X	-	-	12 CP	12 CP	(E)	CC-TRAN
70	TRANMISSION CONTRA			C-TCWIP	X	-	-	Direct	-	(I)	CC-TCWIP-C
71	DISTRIBUTION	107									
72	PRIMARY										
73	OVERHEAD LINES - DEMAND	D300		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
74	OVERHEAD LINES - CUSTOMER	D300		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
75	UNGRD LINES - DEMAND	D400		C-DPUGL	X	-	-	-	Class NCP	(E)	CC-DPUGL
76	UNGRD LINES - CUSTOMER	D400		C-DPUGL	-	-	X	-	Customers	(E)	CC-DPUGL
77	SECONDARY										
78	OVHD LINES - DEMAND	107		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
79	OVHD LINES - CUSTOMER	107		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
80	UNGRD LINES - DEMAND	107		C-DSUGL	X	-	-	-	Sum NCP	(E)	CC-DSUGL
81	UNGRD LINES - CUSTOMER	107		C-DSUGL	-	-	X	-	Customers	(E)	CC-DSUGL
82	OVHD LINE TRANSFRM - DEMAND	107		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSOHT
83	OVHD LINE TRANSFRMS - CUSTOMER	107		C-DSOHT	-	-	X	-	Customers	(E)	CC-DSOHT
84	UNGRD LINE TRANSFRMS - DEMAND	107		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSUGT
85	UNGRD LINE TRANSFRMS - CUSTOMER	107		C-DSUGT	-	-	X	-	Customers	(E)	CC-DSUGT
86	OVHD SERVICES - DEMAND	369		C-DSOHS	X	-	-	-	Sum NCP	(E)	CC-DSOHS
87	OVERHEAD SERVICES - CUSTOMER	369		C-DSOHS	-	-	X	-	Customers	(E)	CC-DSOHS
88	UNGRD SERVICES - DEMAND	369		C-DSUGS	X	-	-	-	Sum NCP	(E)	CC-DSUGS
89	UNGRD SERVICES - CUSTOMER	369		C-DSUGS	-	-	X	-	Customers	(E)	CC-DSUGS
90	LEASED PROPERTY	372		C-DSLEASED	-	-	X	-	Direct	(E)	CC-DSLEASED
91	STREET LIGHTING	373		C-DSLIGHTING	-	-	X	-	Direct	(E)	CD-DSLIGHTING
92	DISTRIBUTION OTHER										
93	METERS	107		C-DSMETERS	-	-	X	Juris Meters	1/3 D,1/3 E, 1/3 C	(E)/(I)	CC-DSMETERS
94	PRODUCTION - DEMAND	107		C-DOPROD	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
95	DISTRIBUTION BULK DELIVERY			C-DODBD	X	-	-	NCP	Class NCP	(E)	CC-DODBD
96	DISTRIBUTION SUBSTATIONS	107		C-DODSUB	X	-	-	-	Class NCP	(E)	CC-DODSUB

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97	DIST BULK DEL SPECIFIC ASSIGN			C-DODBDSA	X	-	-	Direct	-	(E)	CC-DODBDSA
98	DIST PRIMARY SPECIFIC ASSIGN	107		C-DODPSA	X	-	-	Direct	-	(E)	CC-DODPSA
99	GENERAL PLANT										
100	GENERAL PLANT	107		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
101	GENERAL PLANT CONTRA	107		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
102	INTANGIBLE PLANT										
103	INTANGILBE PLANT	107		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
104	**ACCUMULATED DEPRECIATION (AD)**										
105	STEAM										C-OMLXAG
106	PRODUCTION - DEMAND	108, 110		C-Steam	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
107	STEAM CONTRA			C-Steam	X	-	-	Direct	-	(I)	CC-STEAMAD-C
108	HYDRO										
109	PRODUCTION - DEMAND	108, 110		C-Hydro	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
110	PRODUCTION - ENERGY	108, 110		C-Hydro	-	X	-	E-01	E8760	(E)	CC-PROD
111	HYDRO CONTRA - DEMAND			C-Hydro	X	-	-	Direct	-	(I)	CC-HYDROAD-C
112	HYDRO CONTRA - ENERGY			C-Hydro	-	X	-	Direct	-	(I)	CC-HYDROAD-C
113	WIND										
114	PRODUCTION - DEMAND	108, 110		C-Wind	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
115	WIND CONTRA			C-Wind	X	-	-	Direct	-	(I)	CC-WINDAD-C
116	SOLAR										
117	PRODUCTION - DEMAND	108, 110		C-Solar	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
118	TRANSMISSION										
119	TRANSMISSION PRODUCTION	108, 110		C-TPIS	X	-	-	12 CP	4CP A&E	(E)	CC-TPISXCONTRA
120	TRANSMISSION	108, 110		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPISXCONTRA
121	TRANMISSION CONTRA			C-TPIS	X	-	-	Direct	-	(I)	CC-TAD-C
122	DISTRIBUTION	108, 110									
123	PRIMARY										
124	OVERHEAD LINES - DEMAND	108, 110		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
125	OVERHEAD LINES - CUSTOMER	108, 110		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
126	UNGRD LINES - DEMAND	108, 110		C-DPUGL	X	-	-	-	Class NCP	(E)	CC-DPUGL
127	UNGRD LINES - CUSTOMER	108, 110		C-DPUGL	-	-	X	-	Customers	(E)	CC-DPUGL
128	SECONDARY										
129	OVHD LINES - DEMAND	108, 110		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
130	OVHD LINES - CUSTOMER	108, 110		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
131	UNGRD LINES - DEMAND	108, 110		C-DSUGL	X	-	-	-	Sum NCP	(E)	CC-DSUGL
132	UNGRD LINES - CUSTOMER	108, 110		C-DSUGL	-	-	X	-	Customers	(E)	CC-DSUGL
133	OVHD LINE TRANSFRM - DEMAND	108, 110		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSOHT
134	OVHD LINE TRANSFRMS - CUSTOMER	108, 110		C-DSOHT	-	-	X	-	Customers	(E)	CC-DSOHT
135	UNGRD LINE TRANSFRMS - DEMAND	108, 110		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSUGT
136	UNGRD LINE TRANSFRMS - CUSTOMER	108, 110		C-DSUGT	-	-	X	-	Customers	(E)	CC-DSUGT
137	OVHD SERVICES - DEMAND	108, 110		C-DSOHS	X	-	-	-	Sum NCP	(E)	CC-DSOHS
138	OVERHEAD SERVICES - CUSTOMER	108, 110		C-DSOHS	-	-	X	-	Customers	(E)	CC-DSOHS
139	UNGRD SERVICES - DEMAND	108, 110		C-DSUGS	X	-	-	-	Sum NCP	(E)	CC-DSUGS
140	UNGRD SERVICES - CUSTOMER	108, 110		C-DSUGS	-	-	X	-	Customers	(E)	CC-DSUGS
141	LEASED PROPERTY	108, 110		C-DSLEASED	-	-	X	-	Direct	(E)	CC-DSLEASED
142	STREET LIGHTING	108, 110		C-DSLIGHTING	-	-	X	-	Direct	(E)	CD-DSLIGHTING
143	DISTRIBUTION OTHER										
144	METERS	108, 110		C-DSMETERS	-	-	X	Juris Meters	1/3 D,1/3 E, 1/3 C	(E)/(I)	CC-DSMETERS
145	PRODUCTION - DEMAND	108, 110		C-DOPROD	X	-	-	12 CP	4CP A&E	(E)	CC-PROD

Table 4 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/
146	DISTRIBUTION BULK DELIVERY			C-DODBD	X	-	-	NCP	Class NCP	(E)	CC-DODBD
147	DISTRIBUTION SUBSTATIONS	108, 110		C-DODSUB	X	-	-	-	Class NCP	(E)	CC-DODSUB
148	DIST BULK DEL SPECIFIC ASSIGN			C-DODBDSA	X	-	-	Direct	-	(E)	CC-DODBDSA
149	DIST PRIMARY SPECIFIC ASSIGN	108, 110		C-DODPSA	X	-	-	Direct	-	(E)	CC-DODPSA
150	DISTRIBUTION CONTRA			C-DPAD	X	-	X	Direct	-	(I)	CC-DPAD
151	GENERAL PLANT										
152	GENERAL PLANT	108, 110		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
153	GENERAL PLANT CONTRA			C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
154	INTANGIBLE PLANT										
155	INTANGILBE PLANT	111, 115		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
156	**WORKING CAPITAL REQUIREMENTS**										
157	FUEL INVENTORY	151		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
158	MATERIALS & SUPPLIES	154, 163	8/								
159	PRODUCTION - DEMAND	154, 163		C-MSPROD	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
160	TRANSMISSION	154, 163		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
161	DISTRIBUTION - PRIMARY										
162	OVERHEAD LINES - DEMAND	154, 163		C-DPIS	X	-	-	-	Class NCP	(E)	CC-DPIS
163	OVERHEAD LINES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
164	UNGRD LINES - DEMAND	154, 163		C-DPIS	X	-	-	-	Class NCP	(E)	CC-DPIS
165	UNGRD LINES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
166	DISTRIBUTION - SECONDARY										
167	OVHD LINES - DEMAND	154, 163		C-DPIS	X	-	-	-	Sum NCP	(E)	CC-DPIS
168	OVHD LINES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
169	UNGRD LINES - DEMAND	154, 163		C-DPIS	X	-	-	-	Sum NCP	(E)	CC-DPIS
170	UNGRD LINES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
171	OVHD LINE TRANSFRM - DEMAND	154, 163		C-DPIS	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DPIS
172	OVHD LINE TRANSFRMS - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
173	UNGRD LINE TRANSFRMS - DEMAND	154, 163		C-DPIS	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DPIS
174	UNGRD LINE TRANSFRMS - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
175	OVHD SERVICES - DEMAND	154, 163		C-DPIS	X	-	-	-	Sum NCP	(E)	CC-DPIS
176	OVERHEAD SERVICES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
177	UNGRD SERVICES - DEMAND	154, 163		C-DPIS	X	-	-	-	Sum NCP	(E)	CC-DPIS
178	UNGRD SERVICES - CUSTOMER	154, 163		C-DPIS	-	-	X	-	Customers	(E)	CC-DPIS
179	LEASED PROPERTY	154, 163		C-DPIS	-	-	X	-	Direct	(E)	CC-DPIS
180	STREET LIGHTING	154, 163		C-DPIS	-	-	X	-	Direct	(E)	CC-DPIS
181	DISTRIBUTION OTHER										
182	METERS	154, 163		C-DPIS	X	X	X	Juris Meters	1/3 D,1/3 E, 1/3 C	(E)/(I)	CC-DPIS
183	PRODUCTION - DEMAND	154, 163		C-DPIS	X	-	-	12 CP	4CP A&E	(E)	CC-DPIS
184	DISTRIBUTION BULK DELIVERY			C-DPIS	X	-	-	NCP	Class NCP	(E)	CC-DPIS
185	DISTRIBUTION SUBSTATIONS	154, 163		C-DPIS	X	-	-	-	Class NCP	(E)	CC-DPIS
186	DIST BULK DEL SPECIFIC ASSIGN			C-DPIS	X	-	-	Direct	-	(E)	CC-DPIS
187	DIST PRIMARY SPECIFIC ASSIGN	154, 163		C-DPIS	X	-	-	Direct	-	(E)	CC-DPIS
188	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
189	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

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MP Exhibit ___ (Shimmin)
Shimmin Direct Schedule 1
Attachment 1
Volume 2

Table 4 Summary of Functionalization, Classification and Allocation in MP's CCOSS

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190	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
191	PREPAYMENTS - SBPC	18640.6023		C-SBPC	-	X	-	E-01	E8760	(E)	CC-PROD
192	CASH WORKING CAPITAL	-	9/								
193	O&M EXPENSES	-									
194	FUEL	-		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
195	PURCHASED POWER	-		C-PPOWER	X	X	-	Total Purchased Power Exp		(I)	CC-PPOWER
196	PAYROLL	-		C-OMLXFPP	X	X	X	Total O&M Labor Excluding PP		(I)	CC-OMLXFPP
197	OTHER O&M	-		C-OMEXPCWC	X	X	X	O&M Expense CWC		(I)	CC-OMEXPCWC
198	PROPERTY TAXES	-		C-PROPTAX	X	X	X	Total Property Taxes		(I)	CC-PROPTAX
199	PAYROLL TAXES	-		C-OMLABOR	X	X	X	Total O&M Labor		(I)	CC-OMLABOR
200	AIR QUALITY EMISSION TAX	-		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
201	MINNESOTA WIND PRODUCTION TAX			C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
202	MINNESOTA SOLAR PRODUCTION TAX			C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
203	SALES TAX COLLECTIONS	-		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
204	INCOME TAXES	-		C-RATEBASE	X	X	X	Rate Base		(I)	CC-RATEBASE
205	INCOME TAXES (INCREASE)	-		C-RATEBASE	X	X	X	-	Rate Base	(I)	CC-RATEBASEMN
206	**ASSET RETIREMENT OBLIGATION**	23000, 18230		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
207	**ELECTRIC VEHICLE PROGRAM**	18640.0553		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
208	**WORKERS COMP DEPOSIT**	18640.0093		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLAXAG
209	**UNAMORTIZED WPPI TRANSM AMORT**	25300.9030		C-WPPI	X	-	-	12 CP	12 CP	(E)	CC-TPIS
210	**UNAMORTIZED UMWI TRANSACTION COST**	18230.3003		C-UMWI	X	-	-	12 CP	12 CP	(E)	CC-TPIS
211	**UNAMORTIZED BOS 1 and 2**	18230.3011/13		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
212	**CUSTOMER ADVANCES**			C-DOHL						(I)	CC-DOHL
213	PRIMARY OVHD LINES - DEM	252		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
214	PRIMARY OVHD LINES - CUST	252		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
215	SECONDARY OVHD LINES - DEM	252		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
216	SECONDARY OVHD LINES - CUST	252		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
217	**CUSTOMER DEPOSITS**	235		C-ADVANCES	X	-	X	Total Customer Advances		(I)	CC-ADVANCES
218	**OTHER DEFERRED CREDITS - HIBBARD**	25300.9058/9		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
219	**WIND PERFORMANCE DEPOSIT**	25300.9091		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
220	**ACCUMULATED DEFERRED INCOME TAXES**										
221	STEAM - Cr	281-3		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
222	HYDRO - Cr	281-3		C-HYDRO	X	X	-	Hydo PIS		(I)	CC-HYDRO
223	WIND - Cr	281-3		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
224	SOLAR - Cr	281-3		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
225	TRANSMISSION - Cr	281-3		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
226	DISTRIBUTION - Cr	281-3		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
227	GENERAL - Cr	281-3		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
228	STEAM - Dr	190		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
229	HYDRO - Dr	190		C-HYDRO	X	X	-	Hydo PIS		(I)	CC-HYDRO
230	WIND - Dr	190		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
231	SOLAR - Dr	190		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
232	TRANSMISSION - Dr	190		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
233	DISTRIBUTION - Dr	190		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
234	GENERAL - Dr	190		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
235											
236	**OPERATING INCOME**										

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237	**OPERATING REVENUES**										
238	REVENUE FROM SALES BY RATE CLASS AND DUAL FUEL										
239	SALES BY RATE CLASS	440-447		C-RSALES	X	X	X	Direct	Direct	(I)	CC-RSALES
240	DUAL FUEL DEMAND	440-443		C-RDUALFUEL	X	-	-	-	4CP A&E	(E)	CC-PRODMN
241	DUAL FUEL ENERGY	440-443		C-RDUALFUEL	-	X	-	-	E8760	(E)	CC-PRODMN
242	OTHER REVENUE FROM SALES										
243	INTERSYSTEM SALES DEMAND	443		C-RISSALES	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
244	INTERSYSTEM SALES ENERGY	443		C-RISSALES	-	X	-	E-01	E8760	(E)	CC-PROD
245	LP DEMAND RESPONSE	443		C-DEMAND	X	-	-	-	4CP A&E	(E)	CC-PRODMN
246	SALES FOR RESALE DEMAND	447		C-RRESALE	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
247	SALES FOR RESALE ENERGY	447		C-RRESALE	-	X	-	E-01	E8760	(E)	CC-PROD
248	OTHER OPERATING REVENUE (OOR)										
249	ORR - PRODUCTION DEMAND	454, 456.1, 456.4		C-RPROD	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
250	ORR - PRODUCTION ENERGY	456.9		C-RPROD	-	X	-	E-01	E8760	(E)	CC-PROD
251	ORR - TRANSMISSION	454, 456.2, 456.6, 456.9		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
252	ORR - DISTRIBUTION	450, 456.9		C-DPISXCONTRA						(I)	C-DPISXCONTRA
253	DISTRIBUTION - PRIMARY										
254	OVERHEAD LINES - DEMAND	450, 456.9		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
255	OVERHEAD LINES - CUSTOMER	450, 456.9		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
256	UNGRD LINES - DEMAND	450, 456.9		C-DPUGL	X	-	-	-	Class NCP	(E)	CC-DPUGL
257	UNGRD LINES - CUSTOMER	450, 456.9		C-DPUGL	-	-	X	-	Customers	(E)	CC-DPUGL
258	DISTRIBUTION - SECONDARY										
259	OVHD LINES - DEMAND	450, 456.9		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
260	OVHD LINES - CUSTOMER	450, 456.9		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
261	UNGRD LINES - DEMAND	450, 456.9		C-DSUGL	X	-	-	-	Sum NCP	(E)	CC-DSUGL
262	UNGRD LINES - CUSTOMER	450, 456.9		C-DSUGL	-	-	X	-	Customers	(E)	CC-DSUGL
263	OVHD LINE TRANSFRM - DEMAND	450, 456.9		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSOHT
264	OVHD LINE TRANSFRMS - CUSTOMER	450, 456.9		C-DSOHT	-	-	X	-	Customers	(E)	CC-DSOHT
265	UNGRD LINE TRANSFRMS - DEMAND	450, 456.9		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSUGT
266	UNGRD LINE TRANSFRMS - CUSTOMER	450, 456.9		C-DSUGT	-	-	X	-	Customers	(E)	CC-DSUGT
267	OVHD SERVICES - DEMAND	450, 456.9		C-DSOHS	X	-	-	-	Sum NCP	(E)	CC-DSOHS
268	OVERHEAD SERVICES - CUSTOMER	450, 456.9		C-DSOHS	-	-	X	-	Customers	(E)	CC-DSOHS
269	UNGRD SERVICES - DEMAND	450, 456.9		C-DSUGS	X	-	-	-	Sum NCP	(E)	CC-DSUGS
270	UNGRD SERVICES - CUSTOMER	450, 456.9		C-DSUGS	-	-	X	-	Customers	(E)	CC-DSUGS
271	LEASED PROPERTY	450, 456.9		C-DSLEASED	-	-	X	-	Direct	(E)	CC-DSLEASED
272	STREET LIGHTING	450, 456.9		C-DSLIGHTING	-	-	X	-	Direct	(E)	CD-DSLIGHTING
273	DISTRIBUTION OTHER										
274	METERS	450, 456.9		C-DSMETERS	X	X	X	Juris Meters	1/3 D,1/3 E, 1/3 C	(E)/(I)	CC-DSMETERS
275	PRODUCTION - DEMAND	450, 456.9		C-DOPROD	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
276	DISTRIBUTION BULK DELIVERY	450, 456.9		C-DODBD	X	-	-	NCP	Class NCP	(E)	CC-DODBD
277	DISTRIBUTION SUBSTATIONS	450, 456.9		C-DODSUB	X	-	-	-	Class NCP	(E)	CC-DODSUB
278	DIST BULK DEL SPECIFIC ASSIGN	450, 456.9		C-DODBDSA	X	-	-	Direct	-	(E)	CC-DODBDSA
279	DIST PRIMARY SPECIFIC ASSIGN	450, 456.9		C-DODPSA	X	-	-	Direct	-	(E)	CC-DODPSA
280	GENERAL PLANT	450, 456.9		C-OMLXAG	X	X	X	General Plant		(I)	CC-OMLXAG
281	ORR - DISPOSITION OF ALLOWANCES	411.8		C-RDISPALL	-	X	-	-	E8760	(E)	CC-PRODMN
282	ORR - CONSERVATION IMPROV PROGRAM	456.9		C-ENERGY	-	X	-	-	CCRC MWh	(E)	CC-CIP
283	ORR - RENEWABLE RESOURCES RIDER	456.9		C-RRR	X	X	-	12 CP	4CP A&E	(E)	CC-RRR
284	ORR - SOLAR RENEWABLE RESOURCES RIDER	456.9		C-SRRR	-	X	-	12 CP	4CP A&E	(E)	CC-SRRR
285	ORR - TRANSMISSION COST RECOVERY RIDER	456.9		C-TCR	X	X	-	12 CP	12 CP	(E)	CC-TCR

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	ORR - ELECTRIC VEHICLE PROGRAM	456.9		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
286	**OPERATION & MAINTENANCE EXPENSE**										
287	STEAM PRODUCTION										
288	DEMAND	500-3, 505/6, 511, 514		C-OMSTEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
289	ENERGY	510, 512-3		C-OMSTEAM	-	X	-	E-01	E8760	(E)	CC-PROD
290	HYDRO PRODUCTION										
291	DEMAND	535, 537-9, 541-2		C-OMHYDRO	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
292	ENERGY	543-5		C-OMHYDRO	-	X	-	E-01	E8760	(E)	CC-PROD
293	WIND PRODUCTION	546-554		C-OMWIND	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
294	TRANSMISSION	560-2, 565-571, 573		C-TPIS	X	-	-	12 CP	12 CP	(I)	CC-TPIS
295	DISTRIBUTION										
296	METERS	586, 597		C-DSMETERS	X	X	X	Juris Meters	1/3 D,1/3 E, 1/3 C	(E)/(I)	CC-DSMETERS
297	OTHER DISTRIBUTION	580-5, 587-590, 592-8		C-DPISXMETERS	X	-	X	Dist PIS, Excl Meters		(I)	CC-DPISXMETERS
298	OTHER POWER SUPPLY										
299	PRODUCTION DEMAND	556-7		C-POWER	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
300	PURCHASED POWER										
301	DEMAND	555		C-PPOWER	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
302	ENERGY	555		C-PPOWER	-	X	-	E-01	E8760	(E)	CC-PROD
303	FUEL	501		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
304	CUSTOMER ACCOUNTING	901-4		C-CUSTOMER	-	-	X	Expenses & Labor ratios		(E)	CC-OMACCOUNT
305	CUSTOMER SERVICE & INFORMATION	907-10		C-CUSTOMER	-	-	X	Expenses & Labor ratios		(E)	CC-OMSERVICE
306	CONSERV IMPROVEMENT PROGRAM	90806.0000		C-ENERGY	-	X	-	-	CCRC MWh	(E)	CC-CIP
307	SALES	913		C-CUSTOMER	-	-	X	Expenses & Labor ratios		(E)	CC-OMSALES
308	ADMINISTRATIVE & GENERAL										
309	PROPERTY INSURANCE	924		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
310	REGULATORY EXPENSES - MIS0	928		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TPIS
310	REGULATORY EXPENSES - MISC	928		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
311	ADVERTISING	930.1		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
312	FRANCHISE REQUIREMENTS	927		C-RATEBASE	X	X	X	-	Retail Rate Base	(I)	CC-RATEBASEMN
313	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
314	CHARITABLE CONTRIBUTIONS	426.1		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
315	INTEREST ON CUSTOMER DEPOSITS	43100.1001, 43100.1002		C-RATEBASE	X	X	X	Rate Base	Retail Rate Base	(I)	CC-RATEBASEMN
316	**DEPRECIATION EXPENSE**										
317	STEAM	403		C-STEAM	X	-	-	Steam PIS		(E)	CC-PROD
318	STEAM CONTRA			C-STEAM	X	-	-	Direct	4CP A&E	(E)	CC-STEAMDE-C
319	HYDRO DEMAND	403		C-HYDRO	X	-	-	Hydro PIS		(E)	CC-PROD
320	HYDRO ENERGY			C-HYDRO	-	X	-	Hydro PIS		(E)	CC-PROD
321	HYDRO CONTRA			C-HYDRO	X	-	-	Direct	4CP A&E	(E)	CC-HYDRODE-C
322	WIND	403		C-WIND	X	-	-	Wind PIS		(E)	CC-PROD
323	WIND CONTRA			C-WIND	X	-	-	Direct	4CP A&E	(E)	CC-WINDDE-C
324	SOLAR	403		C-SOLAR	X	-	-	Solar PIS		(E)	CC-PROD
325	TRANSMISSION	403		C-TPIS	X	-	-	Transmission PIS		(E)	CC-TPISXCONTRA
326	TRANSMISSION CONTRA			C-TPIS	X	-	-	Direct	12 CP	(E)	CC-TDE-C
327	DISTRIBUTION	403		C-DPISXCONTRA	X	-	X	Distribution PIS		(E)	CC-DPISXCONTRA
328	DISTRIBUTION CONTRA			C-DPAD	X	-	X	Distribution PIS		(E)	CC-DPAD
329	GENERAL PLANT	403		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
330	GENERAL PLANT CONTRA	403		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
331	**AMORTIZATION EXPENSE**										
332	INTANGIBLE PLANT	404		C-OMLXAG	X	X	X	General Plant		(I)	CC-OMLXAG

Minnesota Power
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Table 4 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/
333	UMWI	406, 407.3		C-UMWI	X	-	-	12 CP	12 CP	(E)	CC-TPIS
334	ARO ACCERTION	411.1		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
335	BOSWELL 1 AND 2	40730.11		C-STEAM	X	-	-	12 CP	4CP A&E	(E)	CC-PROD
336	**PROPERTY TAXES**										
337	STEAM	408.1		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
338	HYDRO	408.1		C-HYDRO	X	X	-	Total Hydro PIS		(I)	CC-HYDRO
339	WIND	408.1		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
340	SOLAR	408.1		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
341	TRANSMISSION	408.1		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPISXCONTRA
342	DISTRIBUTION	408.1		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
343	GENERAL PLANT	408.1		C-OMLXAG	X	X	X	Total General PIS		(I)	CC-OMLXAG
344	**PAYROLL TAXES**			C-OMLABOR						(I)	CC-OMLABOR
345	STEAM	408.1		C-OMLSTEAM	X	X	-	O&M Steam Labor		(I)	CC-OMLSTEAM
346	HYDRO	408.1		C-OMLHYDRO	X	X	-	O&M Hydro Labor		(I)	CC-OMLHYDRO
347	WIND	408.1		C-OMLWIND	X	X	-	O&M Wind Labor		(I)	CC-OMLWIND
348	SOLAR	408.1		C-OMLSOLAR	X	X	-	O&M Solar Labor		(I)	CC-OMLSOLAR
349	TRANSMISSION	408.1		C-TPIS	X	-	-	12 CP	12 CP	(I)	CC-TPIS
350	DISTRIBUTION	408.1		C-OMLD	X	-	X	O&M Distribution Labor		(I)	CC-OMLD
351	OTHER POWER SUPPLY	408.1		C-POWER	X	X	X	O&M Other Power Supply		(I)	CC-PROD
352	FUEL	408.1		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
353	CUSTOMER ACCOUNTING	408.1		C-CUSTOMER	-	-	X	O&M Expenses		(E)	CC-OMACCOUNT
354	CUSTOMER SERVICE & INFORMATION	408.1		C-CUSTOMER	-	-	X	O&M Expenses		(E)	CC-OMSERVICE
355	SALES	408.1		C-CUSTOMER	-	-	X	O&M Expenses		(E)	CC-OMSALES
356	ADMIN & GEN	408.1		C-OMLAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLAG
357	**AIR QUALITY EMISSION - PROD ENERGY**	408.1		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
358	**MINNESOTA WIND PRODUCTION TAX**	408.1		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
359	**MINNESOTA SOLAR PRODUCTION TAX**	408.1		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
360	**ADDITIONS AND DEDUCTIONS TO INCOME FOR TAX**										
361	ACCRUED POST EMPL BNFTS -FAS 112 OPRTG	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
362	ACCRUED VACATION	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
363	ARO ACCRETION	various		C-EPIS	X	X	X	Steam Plant		(I)	CC-EPIS
364	ARO AMORTIZATION	various		C-STEAM	X	-	-	Steam Plant		(I)	CC-STEAM
365	BOND ISSUE COSTS (NCL)	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
366	BOSWELL TRANSMISSION AGREEMENT	various		C-TPIS	X	-	-	12 CP	12 CP	(E)	CC-TRAN
367	CAPITALIZED OVERHEADS	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
368	CONSERVATION IMPROVEMENT PROJECT	various		C-ENERGY	-	X	-	-	CCRC MWh	(E)	CC-CIP
369	CONTRIBUTION IN AID OF CONSTRUCTION	various		C-DSOHL	X	X	-	Sum NCP & Customers		(E)	CC-DSOHL
370	COST TO RETIRE	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
371	DEFERRED NON-QUALIFIED PLANS (NCA)	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
372	DEFERRED NON-QUALIFIED PLANS - OPERATING	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
373	DIRECTOR FEES -DEFERRED	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
374	DUES	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
375	EIP DEATH BENEFIT	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
376	EPA NOV	various		C-STEAM	X	-	-	Steam Plant		(I)	CC-STEAM
377	ESPP DISQUALIFING DISPOSITION	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
378	FAS 158 - MONTHLY	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
379	FAS 158 - OCI ADJUSTMENT	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
380	FUEL CLAUSE ADJUSMENT	various		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
381	FUEL TAX CREDIT	various		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD

Table 4 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/
382	INT LONG TERM DEBT (INT SYNCHRONIZATION)	various	10/	C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
383	MEALS AND ENTERTAINMENT	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
384	MEDICAL CLAIMS (CA)	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
385	MEDICARE SUBSIDY	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
386	MISO RESERVE	various		C-REGEXPMISO	X	-	-	12 CP	12 CP	(E)	CC-TRAN
387	ND ITC REGULATORY LIABILIY	various		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
388	NONDEDUCTIBLE PARKING	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
389	OPEB FAS 106 OPERATING	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
390	PENSION EXPENSE - OPERATING (NCA)	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
391	PERFORMANCE SHARES - FAW 123R	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
392	PENALTIES	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
393	POLITICAL ACTIVITIES	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
394	PREPAID BISON EASEMENTS	various		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
395	PREPAID INSURANCE	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
396	PROPERTY TAXES	various		C-PROPTAX	X	X	X	Total Average Rate Base		(I)	CC-PROPTAX
397	RATE CASE RESERVE	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASEMN
398	RESTRICTED STOCK	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
399	RETAIL RATE CASE EXPENSE	various		C-RATEBASE	X	X	X	Total Average Rate Base - Retail		(I)	CC-RATEBASEMN
400	RETIREMENTS	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
401	RSOP	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
402	SEC 162(M) LIMITATION	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
403	SECTION 174	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
404	TAX/BOOK DEPRECIATION DIFFERENCE	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
405	TAX CAPITALIZED INTEREST	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
406	TAX GAIN	various		C-EPIS	X	X	X	Electric Plant In Service		(I)	C-EPIS
407	UNREALIZED BOOK LOSSES	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
408	BAD DEBT EXPESNE	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	CC-RATEBASE
409	EMPLOYEEE EXPENSE - NONDEDCUTIBLE	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
410	OFFICER COMP	various		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
411	**INCOME TAXES**										
412	STATE CURRENT INCOME TAX										
413	ADJUSTED TAXABLE INCOME	-		C-ADJNETINC	X	X	X	CCOSS CALCULATION		-	CC-ADJNETINC
414	STATE NOL UTILIZATION			C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
415	STATE DEPRECIATION MODIFICATION	-		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
416	STATE NET TAXABLE INCOME	-			X	X	X	CCOSS CALCULATION			
417	STATE TAX AT 9.8 PERCENT	-		C-STATETAX	X	X	X	CCOSS CALCULATION			CC-STATETAX
418	STATE TAX CREDITS	-		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
419	CORRECTION TO PRIOR YEARS			C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
420	STATE MINIMUM TAX			C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
421	FEDERAL CURRENT INCOME TAX										
422	FEDERAL TAXABLE INCOME	-		C-ADJNETINC	X	X	X	CCOSS CALCULATION		-	CC-ADJNETINC
423	STATE TAX DEDUCTION	-		C-STATEINCTAX	X	X	X	CCOSS CALCULATION			CC-STATEINCTAX
424	FEDERAL NOL UTILIZATION	-		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
425	FEDERAL NET TAXABLE INCOME	-			X	X	X	CCOSS CALCULATION		-	
426	FEDERAL TAX AT 21 PERCENT	-		C-FEDTAX	X	X	X	CCOSS CALCULATION			CC-FEDTAX
427	TAX CREDITS	-		C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
428	CORRECTION TO PRIOR YEARS			C-EPIS	X	X	X	Electric Plant In Service		(I)	CC-EPIS
429	**PROVISION FOR DEFERRED INCOME TAX**										
430	ACCOUNT 410.1										

Table 4 Summary of Functionalization, Classification and Allocation in MP's CCOSS

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431	STEAM	410.1		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
432	HYDRO	410.1		C-HYDRO	X	X	-	Hydro PIS		(I)	CC-HYDRO
433	WIND	410.1		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
434	SOLAR	410.1		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
435	TRANSMISSION	410.1		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
436	DISTRIBUTION	410.1		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
437	GENERAL	410.1		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG

Table 4 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/
438	**PROVISION FOR DEFERRED INCOME TAX - CREDIT**										
439	ACCOUNT 411.1										
440	STEAM	411.1		C-STEAM	X	-	-		Steam PIS	(I)	CC-STEAM
441	HYDRO	411.1		C-HYDRO	X	X	-		Hydro PIS	(I)	CC-HYDRO
442	WIND	411.1		C-WIND	X	-	-		Wind PIS	(I)	CC-WIND
443	SOLAR	411.1		C-SOLAR	X	-	-		Solar PIS	(I)	CC-SOLAR
444	TRANSMISSION	411.1		C-TPIS	X	-	-		Transmission PIS	(I)	CC-TPIS
445	DISTRIBUTION	411.1		C-DPIS	X	-	X		Distribution PIS	(I)	CC-DPIS
446	GENERAL	411.1		C-OMLXAG	X	X	X		General PIS	(I)	CC-OMLXAG
447	**INVESTMENT TAX CREDIT**										
448	ACCOUNT 411.4										
449	STEAM	411.4		C-STEAM	X	-	-		Steam PIS	(I)	CC-STEAM
450	HYDRO	411.4		C-HYDRO	X	X	-		Hydro PIS	(I)	CC-HYDRO
451	WIND	411.4		C-WIND	X	-	-		Wind PIS	(I)	CC-WIND
452	SOLAR	411.4		C-SOLAR	X	-	-		Solar PIS		CC-SOLAR
453	TRANSMISSION	411.4		C-TPIS	X	-	-		Transmission PIS	(I)	CC-TPIS
454	DISTRIBUTION	411.4		C-DPIS	X	-	X		Distribution PIS	(I)	CC-DPIS
455	**ALLOWANCE FUNDS DURING CONSTRUCTION**										
456	STEAM	419.1, 432		C-STEAMCWIP	X	-	-		Total CWIP Steam	(I)	CC-STEAMCWIP
457	HYDRO	419.1, 432		C-HYDROCWIP	X	X	-		Total CWIP Hydro	(I)	CC-HYDROCWIP
458	WIND	419.1, 432		C-WINDCWIP	X	-	-		Total CWIP Wind	(I)	CC-WINDCWIP
459	SOLAR	419.1, 432		C-SOLARCWIP	X	-	-		Total CWIP Solar	(I)	CC-SOLARCWIP
460	TRANSMISSION	419.1, 432		C-TCWIP	X	-	-		Total CWIP Transmission	(I)	CC-TCWIP
461	DISTRIBUTION	419.1, 432		C-DCWIP	X	-	X		Total CWIP Distribution	(I)	CC-DCWIP
462	GENERAL	419.1, 432		C-OMLXAG	X	X	X		Total CWIP General Plant	(I)	CC-OMLXAG
463	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.

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Comparison of Minnesota Jurisdictional Factors

Line No.	Previous Allocation Code	New UI Allocation Code	Description	Final Ordered Projected Test Year 2022 Docket No. E015/GR-21-335	2022 Actual	2023 Projected	2024 Test Year Docket No. E015/GR-23-155
1	**Demand**			(1)	(2)	(3)	(4)
2	D01	CC-PROD	Power Supply Production	87.62%	88.11%	88.31%	88.65%
3	D02	CC-TRAN	Power Supply Transmission	81.63%	81.84%	82.02%	82.59%
4	D03	CC-DODBD	Distribution Bulk Delivery	71.71%	70.56%	70.56%	71.69%
5	D04	CC-DODSUB	Distribution Substations	100.00%	100.00%	100.00%	100.00%
6	D05	CC-DPOHL	Primary Overhead Lines	100.00%	100.00%	100.00%	100.00%
7	D06	CC-DSOHL	Secondary Overhead Lines	100.00%	100.00%	100.00%	100.00%
8	D07	CC-DPUGL	Primary Underground Lines	100.00%	100.00%	100.00%	100.00%
9	D08	CC-DSUGL	Secondary Underground Lines	100.00%	100.00%	100.00%	100.00%
10	D11	CC-DSOHT	Overhead Line Transformers	100.00%	100.00%	100.00%	100.00%
11	D12	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	85.57%	86.05%	85.70%	85.91%
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	98.87%	98.68%	98.82%	98.82%
28	C12	CC-OMACCOUNT	Customer Accounts	99.18%	99.31%	99.32%	99.32%
29	C13	CC-OMSALES	Sales	100.00%	100.00%	100.00%	100.00%
30	C14	CC-OMSERVICE	Customer Service	98.96%	99.73%	99.75%	99.74%

Interim and Final Rate Increases Net of Riders

Rate change compared to Dec 2024	Interim	Final
Base rates	13.82%	17.17%
TCR offset: GNTL to base rates	-2.2%	-2.2%
RRR offset: PTCs to base rates 1/	-3.0%	-3.0%
Net bill impact	8.6%	12.0%

Revenue Deficiency ($ millions)	Interim	Final	
Base rates	$102.6	$127.9	
TCR offset: GNTL to base rates	(16.4)	(16.4)	2/
RRR offset: PTCs to base rates 1/	(22.4)	(22.4)	3/
Net deficiency	63.8	89.1	

1/ Customers will be credited with the amount of PTCs transferring to base rates effective January 1, 2024, but will not see a reduction in the RRR line of their bills until about October 2024, which is when customers will have paid for carryover PTC amounts from 2023 in the Renewable Resource Rider and the billing factors are expected to go to zero.
2/ Refer to MP Exhibit ___ (Shimmin) Direct Schedule 3, page 2.
3/ Refer to MP Exhibit ___ (Shimmin) Direct Schedule 3, page 3.

Impact of Resetting PTC in Base Rates

Line		Interim Rates 2024
	2024 Budget MWh	731,741
1	2024 Budget MWh	731,741
2	Rate ($/MWh)	29.00
3	2024 PTC	21,220,489
4	2022 Test Year PTC	39,924,985
5	PTC Over/(Under) Test Year vs Test Year	(18,704,496)
6	Deferred Tax Expense	18,704,496
7	Tax Gross Up	71.258%
8	Revenue Requirement Impact	26,248,977
9	Increase/(Decrease) to Avg Mo. Rate Base	(9,352,248)
10	Annual Rate of Return	7.1841%
11	Return on Rate Base	(671,875)
12	Tax Gross Up	71.258%
13	Rate Base Rev Req Impact	(942,876)
14	Total Rev Req Impact	25,306,101
15	MN Jurisdictional Allocator 2024	0.88652
16	MN Jurisdictional Impact of Resetting PTCs	22,434,364

Estimated Revenue Requirements of the GNTL Project Moving from TCR to Base Rate

MN Jurisdictional Project Revenue Requirements ($)	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	2024 Total
ID #105471 Great Northern Transmission Line	2,827,723	2,822,688	3,073,330	2,900,781	2,895,746	2,890,714	2,914,247	2,907,089	2,875,608	2,870,570	2,865,535	2,974,789	34,818,821
ID #107621 Iron Range Substation	225,107	224,710	224,312	223,915	223,517	223,120	222,722	222,325	221,927	221,530	221,133	220,735	2,675,053
ID #107623 Series Comp Station	104,682	104,499	104,315	104,131	103,947	103,763	103,579	103,396	103,212	103,028	102,844	102,660	1,244,056
ID #107626 Blackberry Substation Modifications	3,387	3,381	3,376	3,371	3,365	3,360	3,355	3,349	3,344	3,339	3,333	3,328	40,289
ID #107627 Arrowhead Substation Modifications	859	857	856	855	853	852	850	849	848	846	845	843	10,213
ID #107628 Forbes Substation Modifications	835	834	832	831	830	828	827	826	824	823	822	820	9,932
ID #107629 Hilltop Substation Modifications	688	687	686	685	684	683	681	680	679	678	677	676	8,184
ID #110418 Black River Regen	3,286	3,280	3,274	3,268	3,262	3,257	3,251	3,245	3,239	3,234	3,228	3,222	39,045
ID #110435 GNTL Togo Regen	2,206	2,203	2,199	2,195	2,191	2,187	2,184	2,180	2,176	2,172	2,168	2,165	26,226
ID #110738 GNTL Salol Radio Project	133	132	132	131	131	131	130	130	130	129	129	129	1,567
ID #110742 GNTL Williams Radio Project	111	110	110	110	109	109	109	108	108	108	108	107	1,307
ID #110743 Baudette Radio Project	137	136	136	136	135	135	134	134	134	133	133	132	1,615
ID #110744 GNTL Fairland Radio Project	124	124	124	123	123	123	122	122	122	121	121	121	1,470
ID #110745 GNTL Margie Radio Project	195	194	194	193	193	192	192	191	190	190	189	189	2,302
ID #110747 GNTL Effie Radio Project	241	241	240	239	239	238	237	237	236	235	235	234	2,852
ID #110748 GNTL Marcell Radio Project	100	100	99	99	99	99	98	98	98	97	97	97	1,182
ID #110751 GNTL Shannon Radio Project	78	77	77	77	77	77	76	76	76	76	75	75	917
ID #110753 GNTL Blackberry Radio Project	42	42	42	42	42	41	41	41	41	41	41	41	497
ID #110760 GNTL 115 kV Line 9 Mod	612	611	610	609	608	607	606	605	604	603	602	601	7,279
ID #110761 GNTL 230 kV Line 93	2,538	2,534	2,530	2,525	2,521	2,517	2,513	2,509	2,505	2,500	2,496	2,492	30,181
ID #110764 GNTL 230 kV Line 98	5,210	5,202	5,194	5,187	5,179	5,172	5,164	5,157	5,149	5,141	5,134	5,126	62,015
ID #110766 GNTL 230 kV Line 105	1,995	1,992	1,989	1,985	1,982	1,979	1,975	1,972	1,969	1,966	1,962	1,959	23,726
ID #110767 GNTL 230 kV Line 106	4,803	4,795	4,787	4,779	4,771	4,763	4,755	4,747	4,739	4,732	4,724	4,716	57,112
ID #111173 GNTL Fairland MW Site – MTEP 3831	12	12	12	12	12	12	12	12	11	11	11	11	139
ID #111174 GNTL Salol MW Radio – MTEP 3831	195	194	194	193	193	192	192	191	191	190	190	189	2,304
ID #112139 Iron Range Material Storage Building	57,580	57,452	57,324	57,196	57,068	56,940	56,812	56,684	56,557	56,429	56,301	56,173	682,515
ID #112442 OPGW	45,583	45,502	45,420	45,339	45,258	45,176	45,095	45,013	44,932	44,851	44,769	44,688	541,626
ID #112444 Spare Towers	2,964	2,957	2,951	2,944	2,937	2,931	2,924	2,918	2,911	2,905	2,898	2,892	35,132
Subtotal GNTL Project Revenue Requirements	3,291,424	3,285,545	3,535,344	3,361,951	3,356,072	3,350,197	3,372,886	3,364,885	3,332,560	3,326,678	3,320,799	3,429,210	40,327,554
Estimated MH Payments ($)													
Joint Owner - Operating Expenses /1	(686,396)	(686,396)	(686,396)	(686,396)	(686,396)	(671,649)	(671,649)	(671,649)	(671,649)	(671,649)	(671,649)	(671,649)	(8,133,517)
MH Must Take Fee (133 MW) /2	(1,344,567)	(1,344,567)	(1,344,567)	(1,344,567)	(1,344,567)	(1,294,649)	(1,294,649)	(1,294,649)	(1,294,649)	(1,294,649)	(1,294,649)	(1,294,649)	(15,785,379)
Subtotal MH Estimated Payments	(2,030,963)	(2,030,963)	(2,030,963)	(2,030,963)	(2,030,963)	(1,966,298)	(1,966,298)	(1,966,298)	(1,966,298)	(1,966,298)	(1,966,298)	(1,966,298)	(23,918,896)
Net 2024 Revenue Requirements to Moving Base Rates (at current ROR and with 2021 allocators)													**$ 16,408,658**