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-21-335

Exhibit ________

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

November 1, 2021

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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 Requirement Lead.

Q. Please summarize your qualifications and experience.

A. I have over 15 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 2022 Class Cost of Service Study ("CCOSS") and discuss Minnesota Power's evaluation, selection, and implementation of UIPlanner software to replace its prior Microsoft Excel-based CCOSS model. UIPlanner makes the CCOSS modeling process more efficient, more adaptable to changes in assumptions, and less prone to input errors. 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 address several compliance matters and provide a summary of the changes and updates to the CCOSS since Minnesota Power's last completed rate case, Docket No. E015/GR-16-664 ("2016 Rate Case").

Q. How is your testimony organized?

A. In Section II, I address the compliance matters arising from Minnesota Power's previous rate cases. In particular, I discuss the issues raised by the Department of Commerce, Division of Energy Resources ("Department") in Minnesota Power's 2016 Rate Case related to Minnesota Power's CCOSS model and discuss Minnesota Power's evaluation, selection, and implementation of UIPlanner to replace its prior Excel-based CCOSS model.

Section III presents the results of the 2022 CCOSS using new proposed allocators for Production demand-related costs and Transmission costs. I described these new methodologies and also briefly discuss alternative methodologies Minnesota Power tested.

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.

Section VI addresses Minnesota Power's proposed treatment of our current cost recovery riders in this rate case.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the 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 – Calculation of Production Demand and Transmission Revenue Requirement Indices.

II. COMPLIANCE MATTERS AND NEW CCOSS SOFTWARE

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. Additionally, I provide a discussion regarding Minnesota Power's evaluation of alternatives and selection and implementation of UIPlanner to replace its prior Excel-based CCOSS model. This change stemmed from concerns that were raised in Minnesota Power's 2016 Rate Case regarding transparency and accuracy of the prior CCOSS model.

Q. What compliance matters will you address in this section of your testimony?

A. Order Points 54 and 55 of the Minnesota Public Utilities Commission's ("Commission") Order in the Company's 2016 Rate Case[1] ("2016 Rate Case Order") required that Minnesota Power work with interested parties to improve the transparency of future CCOSS submissions. I also address the requirement in Order Point 20 from the Company's 2009 Rate Case (Docket No. E015/GR-09-1151) ("2009 Rate Case Order")

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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-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 113 at Order Points 54 and 55 (March 12, 2018).

that in future rate case filings, 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.[2] I also address Order Point 1.B from the Company's 2019 Rate Case Resolution (Docket No. E-015/GR-19-442) ("2019 Rate Case Order") regarding parties ability to modify the Company's class cost-of-service model.[3]

Q. What did Order Points 54 and 55 from the 2016 Rate Case require?

A. Order Point 54 required Minnesota Power to work with the Department, the Office of the Attorney General, Residential Utilities and Antitrust Division ("OAG"), and other interested parties to improve the transparency of the Company's future CCOSS.[4] Order Point 55 required the Company to first file a status report within six months of the date of the Order identifying the Company's efforts up to that date to facilitate review of its CCOSS model or adopt a new model.[5] Order Point 54 required the Company to then file a compliance filing within 12 months of the date of the Order explaining the improvements, including the updated CCOSS version and guide. If that version or guide was not yet completed at the 12 month deadline, Minnesota Power was required to file a timeline for completion and future compliance filings.

Q. Has Minnesota Power complied with Order Points 54 and 55 from its 2016 Rate Case?

A. Yes. In response to Order Points 54 and 55, Minnesota Power evaluated whether to continue with its prior Excel-based system CCOSS model or to move to a new CCOSS model. The goal of this evaluation was to identify whether moving to a new software model would make the CCOSS modeling process more efficient, more adaptable to changes in assumptions, more transparent, and less prone to input errors. In the end,

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[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. 2, 2010).

[3] *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-19-442, ORDER APPROVING PETITION AND RESOLVING CASE WITH CONDITIONS at 12 at Order Point 1.B (Aug. 7, 2020).

[4] 2016 Rate Case Order at 113.

[5] *Id.*

Minnesota Power determined that moving to a new CCOSS model using UIPlanner was the best option for improving CCOSS modeling efficiency, accuracy, and transparency.

Q. Did Minnesota Power work with the Department, OAG, and other interested parties in evaluating CCOSS options?

A. Yes. Throughout the evaluation process, Minnesota Power worked with interested parties to determine what improvements could be made to the transparency of Minnesota Power's CCOSS model. Minnesota Power reached out to Commission staff, the Department, the OAG, and the Large Power Intervenor group. Conference calls were held on November 30, 2018, and May 9, 2019, to discuss the status of acquiring and implementing UIPlanner. In addition, parties discussed what specific things stakeholders would like to see in the new CCOSS model and began a general dialogue regarding ways that Minnesota Power could improve its next rate review filing. Stakeholders provided helpful suggestions, including several that have been incorporated into the exportable Excel working model ("EWM") of the CCOSS.

Q. Did Minnesota Power submit the two compliance filings required by Order Points 54 and 55 providing status updates on its CCOSS model evaluation process?

A. Yes. On November 28, 2018, Minnesota Power filed its first compliance filing that described Minnesota Power's process of researching and potentially implementing an alternative CCOSS model.[6] Following this initial compliance filing, Minnesota Power identified UIPlanner as the best tool to modernize the CCOSS modeling process. In its May 22, 2019 compliance filing, Minnesota Power notified the Commission and other interested parties that the Company decided to acquire and implement UIPlanner.[7]

Q. Please generally describe the new UIPlanner.

A. UIPlanner was purchased from Utilities International, an industry leader in planning, budgeting, regulatory, revenue, and accounting solutions for the utility sector.

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[6] *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, CCOSS COMPLIANCE FILING (Nov. 28, 2018).

[7] *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, COMPLIANCE FILING (May 22, 2019).

UIPlanner provides a modeling platform that pulls data directly from Minnesota Power's source systems — Oracle and PowerPlant — to create an accurate, secure, and centralized data repository. Supplemental data can also be imported from Excel spreadsheets. UIPlanner then utilizes all of this data to create models based on actual data, projections, and budgets. The software provides greater transparency by allowing users to query the data within the CCOSS model to identify underlying data and related information and assumptions.

Q. What system was Minnesota Power using prior to converting to UIPlanner?

A. Minnesota Power previously used an Excel-based CCOSS model that was under license from Management Applications Consulting since 1996. This Excel-based CCOSS was a very complex model that was modified, customized, and updated a number of times by Minnesota Power throughout the years. It was built on underlying proprietary macros that were considered trade secret by the vendor and were therefore not accessible to interested parties other than Minnesota Power.

Q. What improvements or efficiencies does UIPlanner provide compared to this prior system?

A. UIPlanner is a much more user-friendly, transparent, and accurate modeling system. The primary issue with Excel models is that they require data to be manually added, which leads to the risk of manual input errors. The inputs and assumptions for these Excel models are also difficult to update.

Q. Can you describe in more detail how UIPlanner will reduce the risk of data input errors?

A. The Excel-based CCOSS model's data had to be manually entered after collecting information from multiple sources in Excel spreadsheets. As a result, updating the data was a labor-intensive process that required a significant amount of time to reconcile the data and ensure its accuracy.

In contrast, UIPlanner reduces the risk of input errors by mapping to sources of data that are derived directly from Minnesota Power's general ledger and other systems. This eliminates the need for manually downloading, linking, copying, and pasting data to create the underlying databases for the model and the associated risk of errors. The new software also pulls associated data, such as the Federal Energy Regulatory Commission ("FERC") account, sub-account, location, function, FERC classification, etc. This allows users to query information to further confirm the origin and accuracy of treatment of the data.

Q. Can you describe in more detail why UIPlanner is easier to update?

A. Updating UIPlanner with new data can generally be done through a direct import process rather than the tedious manual process that was required under the Excel-based CCOSS model. Specifically, the software enables the user to configure filing schedules and other standard reports that can be more efficiently and accurately updated and exported to Excel format.

Q. How will UIPlanner improve Minnesota Power's CCOSS modeling process?

A. Due to the limitations of the Excel software, Minnesota Power's past CCOSS model took a significant amount of time to collect and input data, modify formulas, and reconcile the results with source data. Because the model was driven by macros, it was also challenging for those not familiar with the model to understand the interaction of all of the formulas and data within the model. It was difficult to quickly make changes to the model to examine multiple assumptions.

UIPlanner is more user-friendly in that making changes to the formulas is more intuitive due to the functionality and transparency of the software interface. As a result, users will be able to spend more time analyzing actual data rather than manually entering and reconciling data and results. The new software also allows for relatively quick comparisons to certain "what-if" questions, allowing for more analyses of the data and outputs.

Q. How will UIPlanner improve the CCOSS model that is provided to interested parties?

A. UIPlanner enables the user to configure an exportable EWM with formula and links intact. Because the EWM is configured within the software platform, no manual inputs are required for changes in source data or certain assumptions, such as changes to allocation factors, to flow through to the EWM. Minnesota Power has configured the current version of the EWM taking into consideration input from stakeholders on suggestions for improvements to transparency and usability of the EWM.

The EWM now has clearly defined Total Company input cells where the data is directly exported from the software platform. Minnesota Power has provided an adjustment column to both rate base and income statement line items so other parties can make adjustments without changing the initial input data. Because formula and links are intact, the changes will flow through the model, allowing the user to trace and understand the calculations and see the impact of the changes on total revenue requirements and other results. This is a major improvement over our past Excel-based CCOSS model, which had multiple input areas and required running the model with the imbedded macros, with the output saved in multiple spreadsheets in hard coded values. In addition, feedback from the Company's 2019 Rate Case Resolution was taken into consideration. The EMW now incorporates dynamic allocators and income tax calculations, allowing changes to flow through to final results.

Q. What are other benefits of UIPlanner?

A. In addition to the benefits discussed above, UIPlanner significantly enhances the ability to check the results of the model and understand how they are affected by the input data and modeling assumptions. This will provide greater transparency for regulators and interested stakeholders and increased confidence in the results of Minnesota Power's CCOSS modeling.

Q. Can you summarize the benefits of UIPlanner?

A. In sum, UIPlanner will provide the following benefits: (1) reduce administrative time entering and reconciling data; (2) reduce the potential for data input errors by pulling data directly from Minnesota Power's source systems; (3) enable data updates through an automated, rather than manual, process; (4) allow more transparency through the ability to query data and formulas in order to understand and audit model results; (5) enhance analytical capability by managing and quickly comparing more "what-if" questions; (6) allow quick updates and export of standard reports, including most rate case required financial schedules; and (7) create a more user-friendly and transparent EWM.

Q. What alternatives to updating its CCOSS modeling software did Minnesota Power evaluate?

A. Minnesota Power considered three main options: 1) continue to use the prior Excel-based system; 2) develop a new system in-house; or 3) acquire another modeling system designed for CCOSS.

Q. Why did the Company reject the option of continuing to use the existing Excel-based model?

A. As previously described, the continued use of an Excel-based model had already been deemed problematic given the number of manual processes and lack of transparency of this type of model. Minnesota Power's Excel-based model was initially purchased over 20 years ago. Even with the updates made over the past two decades, the model was not sufficiently robust, nor flexible or transparent enough, to accommodate the increase in the amount of data and the number of different queries that are currently required. Given that the same issues would also be inherent in other Excel-based models, Minnesota Power determined that an Excel-based model was not a prudent option.

Q. What did Minnesota Power conclude after evaluating the option to develop its own in-house CCOSS model?

A. To evaluate this option, Minnesota Power assembled a cross-functional team to look into the possibility of developing an in-house system to automate data flows into one source and feed the data into an Excel-based model. This option was ultimately rejected because of the complexity of modeling required to develop a CCOSS, the risk involved due to a lack of internal expertise of developing such a system, and the lack of resources available to devote to the project. As a result, Minnesota Power determined that developing an in-house model was not a reasonable alternative.

Q. Why did Minnesota Power choose to purchase UIPlanner over other CCOSS software solutions that the Company evaluated?

A. Minnesota Power researched software solutions for CCOSS models and was unable to find another comparable product designed specifically for this purpose. Minnesota Power consulted with other utilities at an Electric Edison Institute ("EEI") conference and informally polled the attendees on what software they used for CCOSS. All of the utilities who joined the discussion reported using either UIPlanner or an Excel-based model, with higher levels of satisfaction expressed by those using UIPlanner. Following the conference, Minnesota Power reached out to the individual utilities who reported using UIPlanner and asked more detailed questions about their experiences with the software — feedback on overall satisfaction, the implementation process, how the software was used, lessons learned, and tips for Minnesota Power. Overall, the feedback from utilities on UIPlanner was positive, with most reporting being very pleased with the product. The positive feedback, along with the lack of other feasible alternatives, convinced Minnesota Power that purchasing UIPlanner was the best option for updating its CCOSS.

Q. What was the cost to implement UIPlanner?

A. The cost to implement UIPlanner was initially estimated at $2.4 million, but the final project cost in 2019 was $1.9 million Total Company.

Q. In addition to implementing UIPlanner, are there other steps that Minnesota Power has taken to address the transparency concerns raised in the Company's 2016 Rate Case?

A. Yes. As discussed above, Minnesota Power believes the current version of EWM is a significant improvement over the previous Excel-based model. In addition, Minnesota Power has also included more detailed schedules on the jurisdictional allocators, bases, and factors in Volume 3, Schedules B-16 to B-19 and Schedule C-13 to C-16. The names and codes of the allocation factors were changed to be more intuitive. MP Exhibit __ (Shimmin), Direct Schedule 1, is a detailed guide to the Company's CCOSS, which includes information on the functionalization, classification, jurisdiction, and customer class allocators used in Minnesota Power's CCOSS. Table 4 in Schedule 1 to my Direct Testimony provides the functionalization, classification, and allocation of each rate base and income statement cost, listing each CCOSS line item cost as it is functionalized and indicating the related FERC account, plant account, or Minnesota Power function code. Table 4 shows how each item is allocated to classification, jurisdiction, and customer class, whether it is allocated with an internal or external allocator, and the name or number of the allocator. Additionally, the Company is also providing improved tables of contents and indices in the filing to make locating supporting files easier.

Q. Has Minnesota Power also complied with Order Point 20 from the Company's 2009 rate case (Docket No. E015/GR-09-1151)?

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 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.

Q. Has Minnesota Power also complied with Order Point 1.B from the Company's 2019 rate case (Docket No. E015/GR-19-442)?

A. Yes. Order Point 1.B required that Minnesota Power shall ensure that parties can modify the Company's class cost-of-service study model inputs and cost allocations and to allow parties to receive real-time calculations and output. It also required the Company to track and report any costs related to complying with this requirement. Minnesota Power re-configured the EWM to make it more dynamic. Users can now modify inputs and external and internal allocators, and the results will flow through the model allowing parties to receive real-time results. As no incremental external costs were incurred to make these updates, no costs were tracked.

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 2022 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 2022 CCOSS Required Revenue Increase by Customer Class Including Dual Fuel

Customer Class	Increase/ (Decrease) to Revenues Required	% Increase/ (Decrease)
Residential	$58,669,881	51.69%
General Service	$11,017,690	14.12%
Large Light & Power	$19,679,062	18.00%
Large Power	$18,425,028	5.92%
Lighting	$522,475	13.66%
Total Retail	**$108,314,136**	**17.58%**

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), the final revenue apportionment approved by the Commission resulted in the Residential class being about 22 percent below its cost of service. In addition, and as discussed in detail below, the above results reflect the new proposed cost allocation methodologies for Production demand-related costs and Transmission costs. The impact of the proposed allocators are shown below in Table 4. These improved methodologies which allocate costs in a more equitable manner, result in a greater allocation to Residential, General Service, and Large Light & Power classes. As a result of this history, combined with the change in allocation methods, and the increase in the overall revenue deficiency since the Company's 2016 Rate Case, the Residential class is now even further away from its cost of service.

In addition to the above, the increase for the Lighting class reflects the fact that changes to a small class can have a disproportionately large impact. Since Minnesota Power's 2016 Rate Case, lighting Plant-in-Service directly assigned to the Lighting class increased.

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. 2022 Adjusted Test Year Class Revenue Requirements by Classification Including Dual Fuel

Customer Class	Customer	Demand	Energy	Total
Residential	$37,791,409	$96,440,832	$37,937,388	$172,169,629
General Service	$7,775,757	$56,078,271	$25,188,357	$89,042,385
Large Light & Power	$788,456	$86,561,640	$41,656,539	$129,006,635
Large Power	$432,424	$198,651,251	$130,613,432	$329,697,107
Lighting	$2,938,539	$970,211	$439,024	$4,347,774
Total Retail	**$49,726,585**	**$438,702,205**	**$235,834,740**	**$724,263,530**

Table 3. 2022 Adjusted Test Year Class Revenue Requirements by Function and Classification Including Dual Fuel

Function & Classification	Total Minnesota Jurisdiction	Residential	General Service	Large Light and Power	Large Power	Lighting
Production	$535,796,490	$ 92,603,088	$56,896,542	$ 96,471,972	$288,751,275	$1,073,613
Demand	$299,961,752	$ 54,665,702	$31,708,185	$ 54,815,431	$158,137,845	$ 634,589
Energy	$235,834,738	$ 37,937,386	$25,188,357	$ 41,656,541	$130,613,430	$ 439,024
Transmission	$ 71,699,367	$ 11,166,578	$ 7,311,421	$ 13,081,755	$ 40,048,092	$ 91,521
Demand	$ 71,699,367	$ 11,166,578	$ 7,311,421	$ 13,081,755	$ 40,048,092	$ 91,521
Dist Bulk Delivery	$ 12,520,921	$ 4,704,472	$ 3,102,372	$ 4,201,095	$ 465,317	$ 47,665
Demand	$ 12,520,921	$ 4,704,472	$ 3,102,372	$ 4,201,095	$ 465,317	$ 47,665
Distribution Primary	$ 48,086,677	$ 23,971,114	$11,461,115	$ 12,082,851	$ -	$ 571,597
Demand	$ 36,823,499	$ 14,855,598	$ 9,769,817	$ 12,047,554	$ -	$ 150,530
Customer	$ 11,263,178	$ 9,115,516	$ 1,691,298	$ 35,297	$ -	$ 421,067
Distribution Secondary	$ 30,985,820	$ 20,009,153	$ 6,064,015	$ 2,452,012	$ -	$2,460,640
Demand	$ 17,696,670	$ 11,048,481	$ 4,186,476	$ 2,415,807	$ -	$ 45,906
Customer	$ 13,289,150	$ 8,960,672	$ 1,877,539	$ 36,205	$ -	$2,414,734
Meters	$ 10,115,946	$ 7,755,717	$ 1,948,760	$ 126,605	$ 265,876	$ 18,988
Customer	$ 10,115,946	$ 7,755,717	$ 1,948,760	$ 126,605	$ 265,876	$ 18,988
Services	$ 15,058,313	$ 11,959,501	$ 2,258,162	$ 590,352	$ 166,545	$ 83,753
Customer	$ 15,058,313	$ 11,959,501	$ 2,258,162	$ 590,352	$ 166,545	$ 83,753
Total	$724,263,534	$172,169,623	$89,042,387	$129,006,642	$329,697,105	$4,347,777

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 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 2022 test year General Rates shown above?

A. Yes, a number of other CCOSS results were generated, including 2020 Most Recent Fiscal Year CCOSS, 2021 Projected Fiscal Year CCOSS, Unadjusted Test Year 2022 CCOSS, and Interim Test Year 2022 CCOSS. All of these CCOSS results are based on Minnesota Power's previously approved cost allocation methods. These results are included in Volume 4, Workpapers and Studies, COS-1 to COS-4. The various rate making adjustments incorporated into the General Rate CCOSS and the Interim Rate CCOSS are discussed by Company witness Amanda L. Turner.

B. Proposed Cost Allocation Methods and Testing of Other Methods

Q. Does Minnesota Power's proposed 2022 CCOSS use the same classification and allocation methodologies considered by the Commission in Minnesota Power's 2016 Rate Case?

A. Yes and no. As discussed in detail below, the Company's 2022 CCOSS includes proposed new allocation methodologies for Production demand-related costs and Transmission costs. Apart from these proposed changes, and apart from minor refinements discussed below, the CCOSS in the present filing uses the same major classification and allocation methodologies considered by the Commission in Minnesota Power's 2016 Rate Case. They are also the same methodologies approved by the Commission in Minnesota Power's 2008 and 2009 rate cases.

To further facilitate use of the CCOSS, however, Minnesota Power also renamed the external and internal allocation code names to make them more intuitive and easier to work with in UIPlanner. These changes are reflected in the Guide to Minnesota Power's CCOSS, which is attached to my Direct Testimony as MP Exhibit ___ (Shimmin), Direct Schedule 1, and also in Volume 3, Direct Schedules B-16 to B-19 and C-13 to C-16.

Q. Can you briefly identify Minnesota Power's proposed 2022 cost allocation methodologies?

A. Yes. Since the Company's 2008 rate case, the Company has used the Peak & Average or P&A methodology to allocate fixed production demand-related costs and transmission costs to our Minnesota Jurisdictional classes. The Company is proposing to replace this fixed production demand-related cost allocator with a method called the Four Coincident Peak Average and Access method ("4CP A&E"). For transmission costs, the Company is proposing to replace the P&A allocator with a method called Twelve Monthly Coincident Peak method ("12CP"). These are discussed in detail below after some background on the P&A is provided. The proposed changes do not impact the Company's FERC/MN Jurisdictional allocators.[8]

Q. Could you briefly describe the Peak & Average methodology?

A. Yes. The Peak & Average methodology has been used by Minnesota Power in our last three completed rate cases (2008, 2009, and 2016) to allocate fixed production demand-related and transmission costs to customer class based on a composite allocation factor that is composed of two parts, as shown below:

Composite Allocation Factor = (1 – LF) x (Coincident Peak Demand Factor)

+

System Load Factor (LF) x (Average Demand Factor)

[8] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided in Volume 3, Direct Schedules B-16 to B-19 and C-13 to C-16.

Q. Could you provide some background or historical context for the Company's use of the Peak & Average methodology?

A. Yes. In four retail rate cases from 1980 to 1994, Minnesota Power used production and transmission retail class allocation factors based on the Average and Excess/Probability of Deficiency methodology, or CAPSUBPOD as it was often called. After Minnesota Power's 1994 rate case, the computer platform on which this program ran was replaced, rendering the program obsolete. Because the consultant that developed and updated the program was no longer available prior to Minnesota Power's subsequent 2008 rate case, it was necessary to develop a new methodology.

In the Company's 1980 rate case (Docket No. E015/GR-80-76), the Minnesota Department of Public Service, (now the Department of Commerce, Division of Energy Resources), recommended the P&A methodology as an alternative to the CAPSUBPOD methodology. The P&A methodology was recommended "because it does a reasonably good job of allocating the revenue requirements to the various classes and it is also understandable and a reasonably straight forward method."[9]

Minnesota Power subsequently selected the P&A methodology for use in the 2008 rate case. This methodology was subsequently used, approved, or considered by the Commission in Minnesota Power's last three completed retail rate cases.

Q. Would you explain why the Company is proposing to discontinue use of the P&A methodology?

A. Yes. After the Company withdrew its 2019 rate case in the midst of the COVID-19 pandemic, a review of the P&A methodology was conducted. The review concluded that support for the P&A methodology is no longer warranted for a number of reasons, including the following:

- The P&A method results in an unequitable allocation of costs;

[9] *In the Matter of the Petition of Minn. Power and Light Co. for Auth. to Change its Schedule of Rates for Elec. Serv. Furnished to its Customers in the State of Minn.*, Docket No. E015/GR-80-76, DIRECT TESTIMONY OF PHILLIP ZINS at 29 (July 11, 1980).

- The P&A method penalizes efficient, high load factor customers;
- The P&A method has an inherent double counting flaw;
- The P&A method is out of favor in the electric industry; and
- The P&A method does not provide good cost signals needed for utility of the future initiatives.

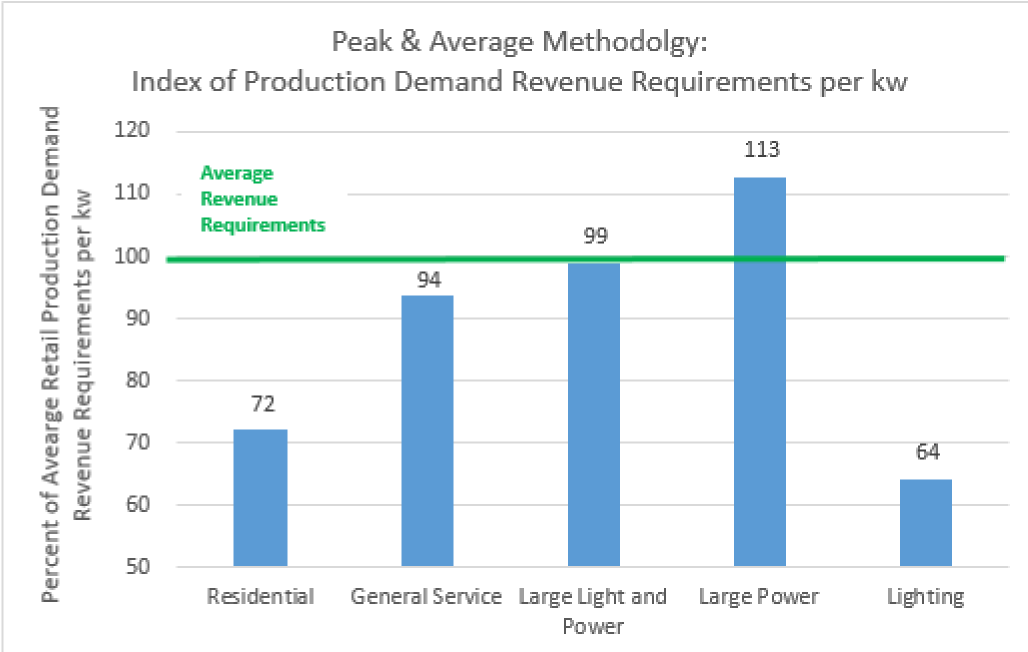
I will address each of these points below.

Q. Would you illustrate how the P&A method results in an unfair and unequitable allocation of costs?

A. Yes. This is illustrated in Figure 1 below. This chart was developed using the production demand revenue requirements allocated to each class using the P&A allocators. The revenue requirements were then divided by each class's contribution to the coincident peak to estimate a unit revenue requirements per kilowatt ("kW"). The total Minnesota Jurisdictional system average unit revenue requirement per kW is set as 100 in the index. The other classes are then indexed comparing to the system average.

As can been seen in Figure 1, the Residential class cost index is far below the system average, illustrating an unfair and unequitable cost allocation. Because the P&A method is also used to allocate transmission revenue requirements, an index for transmission revenue requirements would show the same unequitable results. Taken together, production demand and transmission revenue requirements account for approximately 51 percent of all Minnesota Jurisdictional revenue requirements.

Figure 1: P&A Index of Production Demand Revenue Requirements



Refer to Schedule 3 attached to my Direct Testimony for further details on the calculation of the above index.

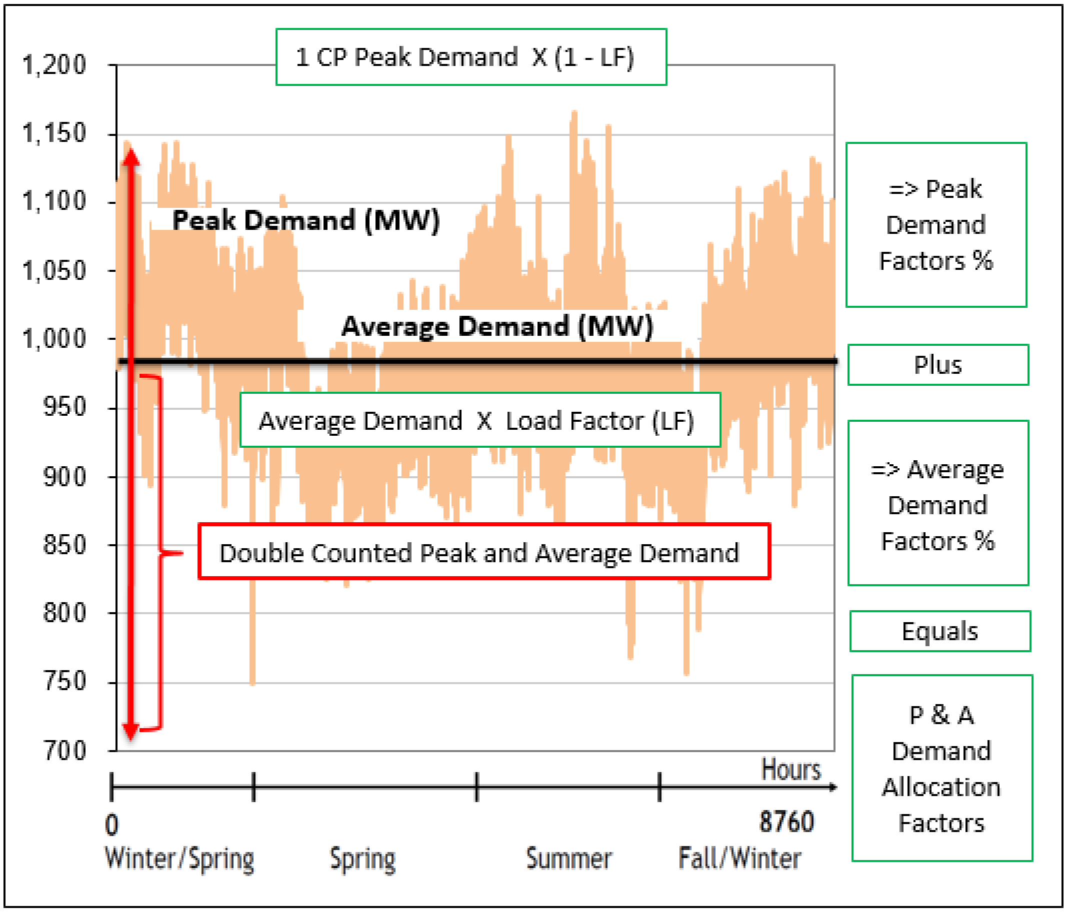
Q. Would you explain how the P&A method penalizes efficient, high load factor customers?

A. Yes. High load factor customers on Minnesota Power's system operate mostly around the clock. This is an efficient use of resources and helps keep all customers costs lower by efficiently utilizing the system and spreading fixed costs over more billing units. The excess cost allocation to the Large Power class, as illustrated in Figure 1 above, penalizes these customers and burdens them with additional costs which do not accurately reflect cost causation.

Q. Would you illustrate the P&A's inherent double counting flaw?

A. Yes. As explained above, the P&A methodology calculation uses each class's contribution to the single coincident peak in the peak demand factor portion of the composite allocator. As illustrated below, the average demand portion of the peak demand is double counted and is included in the peak demand factors of the composite allocator.

Figure 2: Double Counting Flaw in P&A Methodology



Q. Can you explain why you state that the P&A method is out of favor in the electric industry?

A. Yes. In June 2021, at Minnesota Power's request, EEI carried out a survey of its electric utilities members. The survey requested each member to identify each type of allocation methodology it uses across its system. Of the 34 members that responded and reported a production allocator, none used the P&A method. A similar survey conducted at the request of another member in 2007 that showed the same results — none of the respondents used the P&A method.

Q. Would you explain why the P&A method does not provide good cost signals needed for utility of the future initiatives?

A. Yes. Customers are growing increasingly sophisticated and continue to look to Minnesota Power as a trusted source of accurate, honest, and fair information to guide their investment and operational decisions. The Company is currently a leader in a number of areas as the industry transforms in an ever and rapidly changing landscape. As demonstrated above, the P&A method does not allocate production demand and transmission costs in a fair and equitable manner. It therefore will not provide the accurate price information that customers need to make informed decision that will not only impact their own operations, but also could likely impact the overall system and all other customers as well.

Q. Would you briefly explain the new 4CP A&E methodology the Company is proposing to use in allocating fixed production demand-related costs?

A. Yes. The Average & Excess methodology is characterized as an "Energy Weighting Method" by the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Manual") at page 49. It is a composite allocation factor that is composed of two parts, as shown below:

Composite Allocation Factor = (1 – LF) x (Excess Demand Factor)

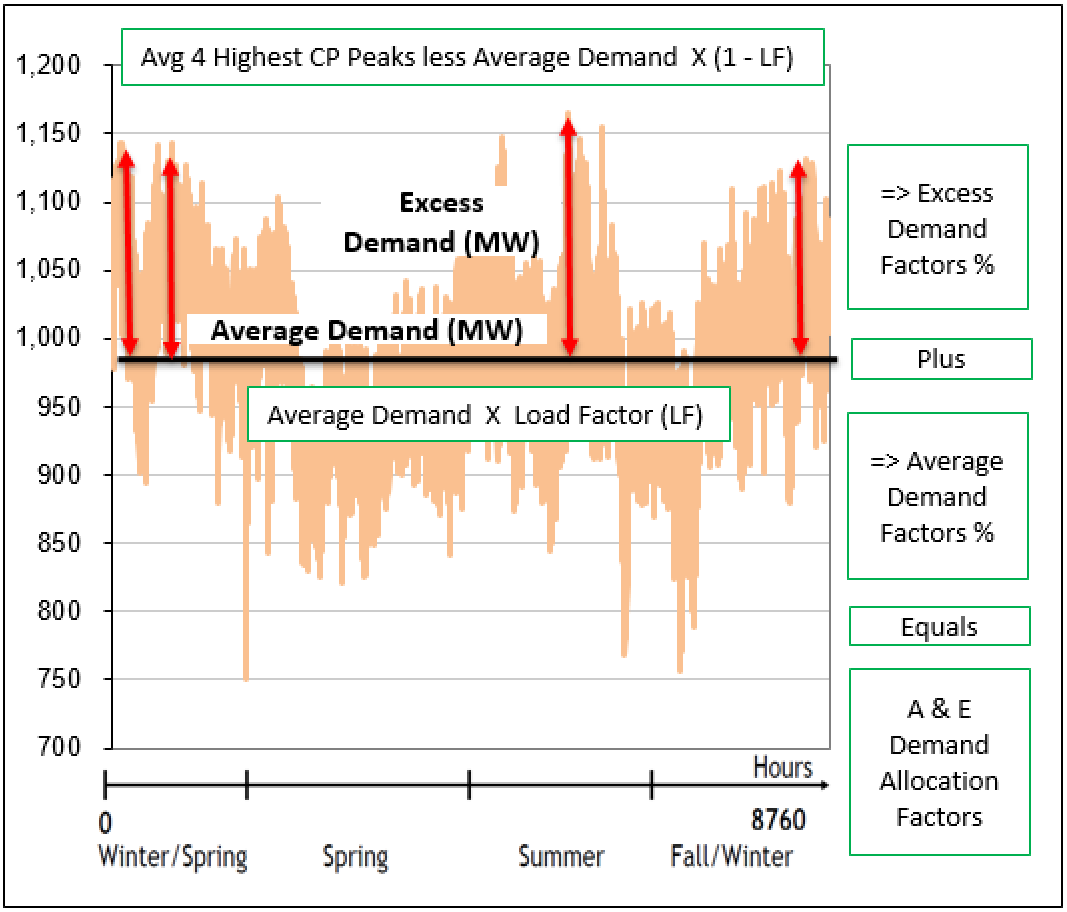
+

System Load Factor (LF) x (Average Demand Factor)

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

The methodology is illustrated in the figure below.

Figure 3: 4CP A&E Methodology



Q. Would you briefly explain why the Company is proposing to use of the 4CP A&E methodology?

A. Yes. As discussed further in my Direct Testimony, the Company compared numerous other methodologies to the P&A method. The Company is proposing to use the 4CP A&E allocator for a number of reasons, including the following:

- The 4CP A&E method results in more equitable allocation of costs;
- The 4CP A&E method better reflects cost-causation;
- The A&E method is a common and well established method; and
- The 4CP A&E method would provide better cost signals needed for utility of the future initiatives.

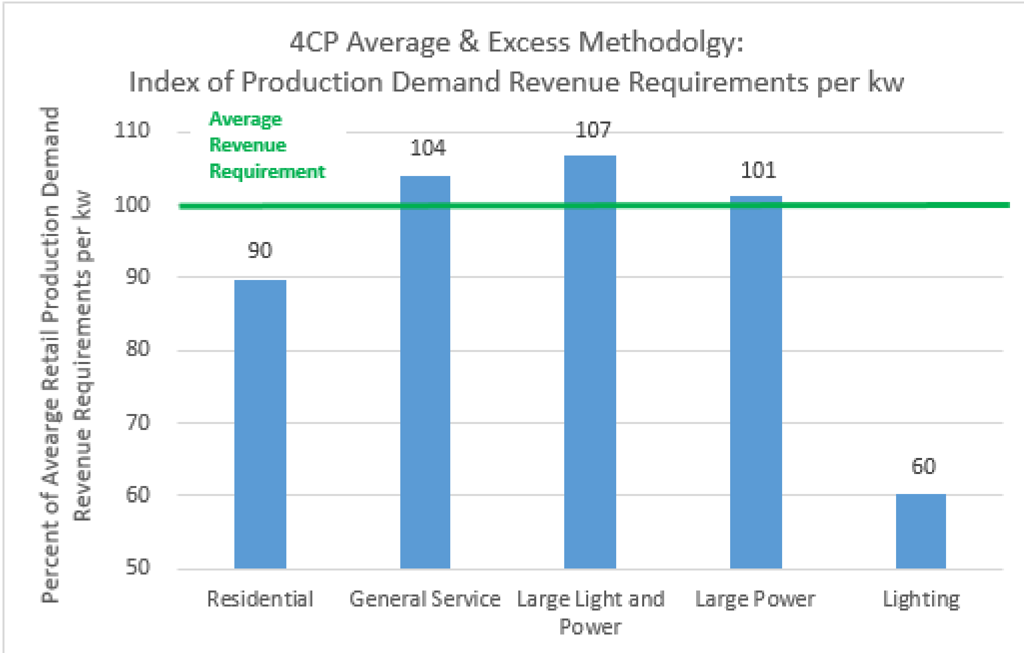
I will address each of these points below.

Q. Would you illustrate how the 4CP A&E method results in fairer and more equitable allocation of costs?

A. Yes. This is illustrated in the Figure 4 below. This chart was developed using the production demand revenue requirements allocated to each class using the 4CP A&E allocators. The revenue requirements were then divided by each class's contribution to the coincident peak to estimate a unit revenue requirements per kW. The total Minnesota Jurisdictional system average unit revenue requirement per kW is set as 100 in the index. The other classes are then indexed comparing to the system average.

As can been seen in Figure 4, the Residential class cost index is much closer to the system average than with the P&A method shown above in Figure 1, illustrating a much fairer and more equitable cost allocation. Similarly, the Large Power class cost index is much closer to or at the system average. As this is by far the largest class on the Company's system, it make sense that it should be just about at the average. While General Service and Large Light & Power classes are above the system average, as discussed below, this reflects cost causation and will help send improved cost signal to these classes.

Figure 4: 4CP A&E Index of Production Demand Revenue Requirements



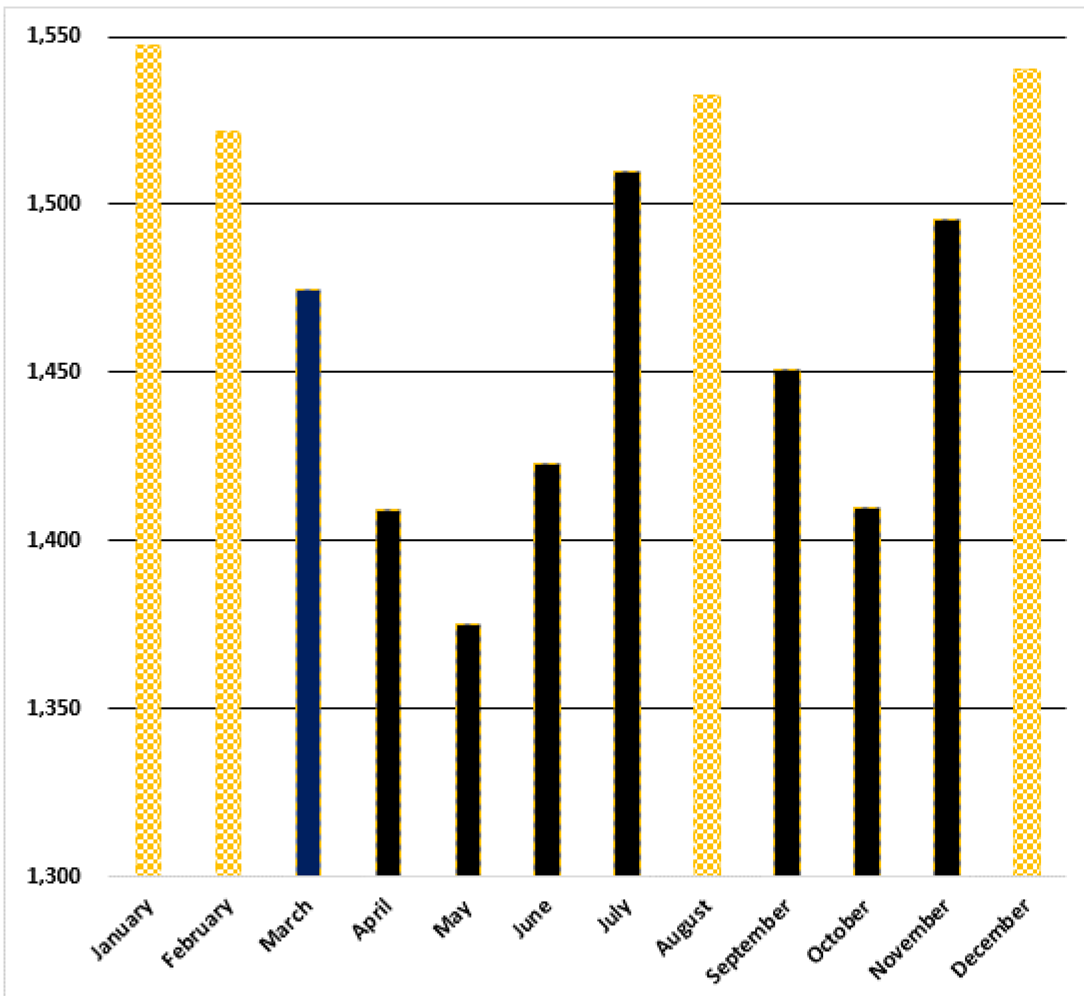
Refer to Schedule 3 attached to my Direct Testimony for further details on the calculation of the above index.

Q. Would you illustrate how the 4CP A&E method better reflects cost-causation?

A. Yes. As illustrated in Figure 3 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.

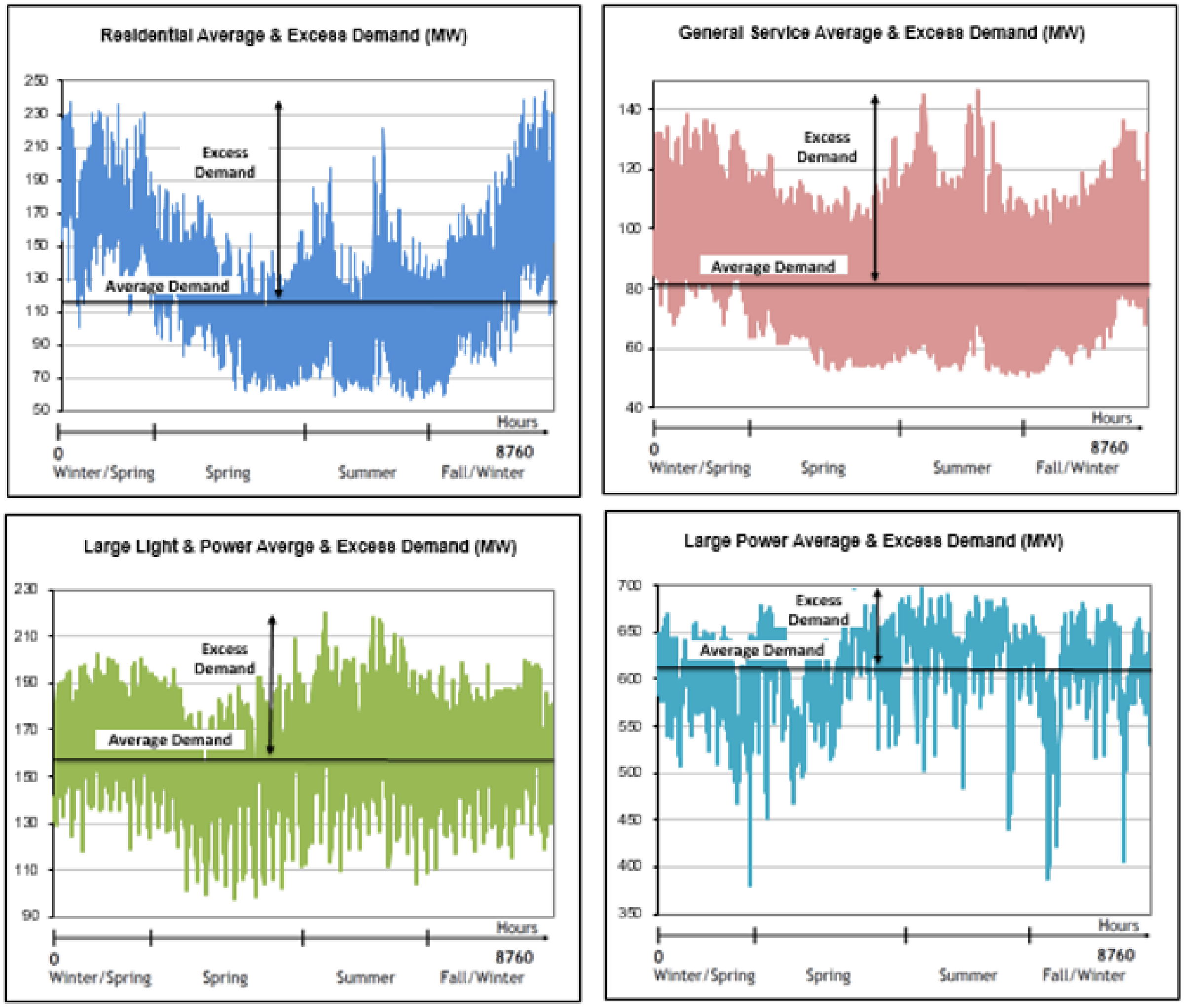
The 4CP A&E method also captures the impact of each class on the Company's four highest peaks. The Company is unique in that it is a winter peaking utility with strong summer peaks and, therefore, must plan to meet the demand of those peaks accordingly. Historically, the average of the four highest peaks 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, better reflect cost causation. Figure 5 below shows Minnesota Power's historic average system peaks by month in yellow.

Figure 5: Minnesota Power's Four Highest Average System Peaks 2010-2020 Megawatt ("MW")



As illustrated in the example below in Figure 6, 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 better 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.

Figure 6: Illustration of A&E Demands by Class



Q. Would you briefly explain your statement that the 4CP A&E method is a common and well established method?

A. Yes. In June 2021, at Minnesota Power's request, the EEI carried out a survey of its electric utilities members. The survey requested each member to identify each type of allocation methodology it uses across its system. Of the 34 members that responded and reported a production allocator, 26 percent use some form of the A&E method, almost 24 percent use some form of straight peak method (12CP, 4CP, 1CP), 29 percent use a combination of peaks and energy, and the remaining 21 percent are about equally represented by the stratification method, loss of load probability method, or straight energy method. And as noted above, the A&E methodology is discussed in the NARUC Manual.

Q. Would you briefly explain your statement that the 4CP A&E method would provide better cost signals needed for utility of the future initiatives?

A. Yes. As demonstrated above, the 4CP A&E method more fairly allocates costs in proportion to each class's average demand and their contribution to the system peaks that are in excess of their average demand. By capturing or accounting for each class's unique load characteristics, the 4CP A&E method would provide better cost signals needed for utility of the future initiatives. For example, a more accurate cost allocation method would be preferred when considering peak shifting or peak reduction programs which support lower overall system costs. This methodology would better align with the Company's Residential time of day, Large Light & Power time of use, and Large Power demand response initiatives while being more supportive of Commission policy on rate design.

Q. Would you briefly explain why the Company is proposing to use the 12CP method for allocating transmission costs?

A. Yes. The Company is proposing to use the 12CP allocator because it is a better allocator compared to the P&A method for a number of reasons, including the following:

- The 12CP method results in fairer and more equitable allocation of costs;
- The 12CP method aligns with how other transmission cost are incurred and allocated by Minnesota Power;
- The 12CP method is a common and well established method; and
- The 12CP method would improve transparency in price signals to customers.

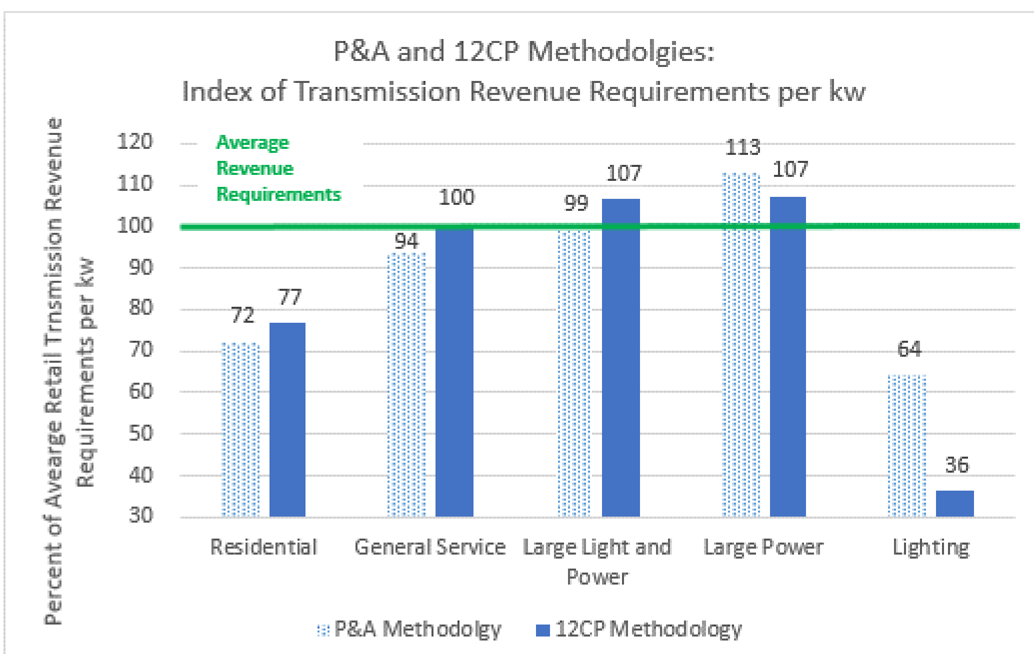
I will address each of these points below.

Q. Would you illustrate how the 12CP method results in fairer and more equitable allocation of costs?

A. Yes. This is illustrated in the Figure 7 below. This chart was developed using the transmission revenue requirements allocated to each class using the 12CP allocators. The revenue requirements were then divided by each class's contribution to the coincident peak to estimate a unit revenue requirements per kW. The total Minnesota Jurisdictional system average unit revenue requirement per kW is set as 100 in the index. The other classes are then indexed comparing to the system average.

As can been seen below in Figure 7, with the 12CP allocation methodology, the Residential class cost index is closer to the average and the General Service class cost index is at the average. While the Large Light & Power class cost index moved above the average, the Large Power class moved closer. As the allocation is based on each class's 12 month average coincident peak contribution, the results are fairer and more equitable than the P&A method.

Figure 7: Comparison of P&A and
12CP Transmission Revenue Requirement Indices



Refer to Schedule 3 attached to my Direct Testimony for further details on the calculation of the above index.

Q. Would you explain your statement that the 12CP method aligns with how other transmission costs are incurred and allocated by Minnesota Power?

A. Yes. The 12CP allocator is the same allocator used for Minnesota Power's jurisdictional allocation, which has been approved and used for decades. The 12CP method also 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.

Q. Would you explain your statement that the 12CP method is a common and well established method?

A. Yes. In June 2021, at Minnesota Power's request, the EEI carried out a survey of its electric utilities members. The survey requested each member to identify each type of allocation methodology it uses across its system. Of the 34 members that responded and reported a transmission allocator, 47 percent use the 12CP method, and another 29 percent use either 4CP or 1CP methods. The 12CP methodology is discussed on page 79 of the NARUC Manual.

Q. Would you explain how the 12CP method would improve transparency in price signals to customers?

A. Yes. The 12CP allocator method is a straight forward, simple, and very easy to understand allocator. The Company believes this would improve customer understanding of how costs are being allocated to them in comparison to the P&A method. As mentioned above, aligning with how other transmission costs are incurred and allocated is very important for customer cost transparency.

Q. Would you summarize the revenue requirement impact by class of using the proposed methods compared to the P&A method?

A. Yes. Table 4 below compares the Adjusted Test Year 2022 revenue increase using the P&A method to both of the proposed methods separately and combined. The combined results were also previously shown in Table 1 above.

Table 4. Adjusted Test Year 2022 CCOSS Required Revenue Increase by Customer Class using the P&A Method Compared to the Proposed 4CP A&E and 12CP Methods

Customer Class	Required % Increase/(Decrease) by Method			
	P&A	4CP A&E Only	12CP Only	4CP A&E and 12CP
Residential	41.57%	51.10%	42.16%	51.69%
General Service	9.43%	13.49%	10.05%	14.12%
Large Light & Power	13.46%	17.14%	14.32%	18.00%
Large Power	12.35%	6.57%	11.69%	5.92%
Lighting	16.56%	15.49%	14.73%	13.66%
Total Retail	**17.58%**	**17.58%**	**17.58%**	**17.58%**

Q. Would you please summarize your recommendation to the Commission on the Company's proposed 4CP A&E and 12CP allocation methodologies?

A. Yes. As demonstrated above, the Company's proposed allocators would result in the more equitable allocation of costs, better reflect cost-causation, improve cost signal to customers, and better position Minnesota Power to continue to provide utility of future initiatives and programs that can benefit both customers and the system as a whole.

To the extent the Commission follows the CCOSS revenue requirement allocation in its cost apportionment decisions, the proposed methods would help align Minnesota Power's industrial competitiveness relative to other states in a manner consistent with State policies to promote growth in jobs and industry and to have fair and reasonable rates.

As discussed by Company witnesses Jennifer J. Cady, Frank L. Fredrickson, and Daniel W. Gunderson, the Company continues to transform its system and lead in delivering customer programs which meet or surpass state renewable energy goals while providing benefits to all customers and the overall system. The Company will need to make significant investments in the coming decade to keep pace with changing technologies, regulatory requirements, and customer expectations. Improved costs allocation methodologies which are equitable, reasonable and reflect cost causation will help the Company design and deliver customer programs which provide better cost signals to meet customer expectations. As the Company transitions to a cleaner energy future in an increasingly data driven environment, improved cost allocations will provide the Company with an enhanced tool box to meet increasing customer expectations. The Company therefore requests the Commission expressly approve the recommended cost allocation methodologies.

Q. Did the Company test other allocation methodologies apart from those proposed above?

A. Yes. The Company tested an additional six other allocator methodologies for production demand costs.

Q. Would you please briefly describe the other methodologies the Company tested for production demand costs and summarize the findings?

A. Yes. Table 5 below summarizes the index of production demand revenue requirements per kW for each method tested in addition to those described above. The Company additionally tested four peak demand methods: 12CP, 4CP, 1CP, and 4CP MISO. In addition, the Company tested two other variants of the A&E method: 12CP A&E and NCP A&E.

Table 5. Index of Production Demand Revenue Requirements per kW for Other Tested Methodologies

Methodology	MN Juris	Residential	General Service	Large Light & Power	Large Power	Lighting
P&A	100	72	94	99	113	64
12CP	100	77	100	107	107	36
12CP A&E	100	81	104	110	104	27
NCP A&E	100	85	103	103	104	71
4CP	100	87	103	106	103	60
4CP A&E	100	90	104	107	101	60
1CP	100	100	100	100	100	100
4CP MISO	100	100	106	106	98	58

Q. Would you please briefly explain the conclusions drawn from the above findings?

A. Yes. The results show the P&A method under allocates production demand costs to the Residential class and over allocates costs to the Large Power class in comparison to all other methods tested. The A&E methods generally allocate more to the General Service class and Large Light & Power class compared to the straight peak methods, apart from the 4CP MISO method. The 4CP MISO method is an outlier for comparative purposes as the timing of the peak measurements are not driven by Minnesota Power system peaks as with the other methods.

C. <u>Other Refinements to the CCOSS</u>

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

A. In this section, I identify other changes to the CCOSS and associated inputs, apart from the overall move to UIPlanner discussed earlier in my testimony. Most of these changes are in the nature of limited refinements, and I walk through each in turn below.

Q. Have there been any changes to the Company's rate classes since Minnesota Power's last rate case that would affect the CCOSS?

A. Yes. As approved in our 2016 Rate Case, Minnesota Power closed the Municipal Pumping rate schedule to new customers and those customers moved to the General Service class. Therefore, the Municipal Pumping class is no longer in the CCOSS.

Q. Please provide an overview of the other changes to the CCOSS.

A. In the process of implementing UIPlanner, a number of minor changes were made to the CCOSS. However, no changes were made to the main methodologies the Company used in past cases. Rather, these changes were refinements in how certain rate base and income statement costs are handled. Direct mapping of data from Minnesota Power's source systems and the structured nature of software coding afforded Minnesota Power the opportunity to make refinements that improve consistency in approach and presentation, accuracy in processing, and greater flexibility to accommodate future changes.

Q. Would you please summarize the specific refinements made to developing rate base?

A. Yes. Refinements have been made in the treatment of deductions, additional reporting lines have been added for solar costs and electric vehicle costs, a refinement was made for handling the contra account of allowance for funds used during construction ("AFUDC") internal allocators, additional mapping has been incorporated for construction work in progress – Distribution ("CWIP – Distribution"), internal allocators related to land have been eliminated, and the control of actual data for prepayments has been changed.

Q. Would you please briefly discuss the handling of deductions to rate base?

A. In Minnesota Power's previous CCOSS, amounts that reduce rate base were subtracted by formula. The new model was configured to take advantage of tree structures that enable amounts to be to be rolled up, or summarized, at various tree levels. Because of this, any amount that is a reduction or deduction to rate base now has a negative sign.

Q. Would you please explain the additional solar reporting line?

A. Yes. In Minnesota Power's 2016 rate case, there were very small amounts of rate base and income statement costs related to new solar projects. Instead of creating new line items for the unadjusted CCOSS, these amounts were added to steam accounts and then were properly pulled out of the adjusted test year. Solar accounts are now directly mapped from source data to separate solar rate base reporting lines. As discussed below in Section VI, all solar costs are pulled out of the 2022 test year budget via the Continuing Cost Recovery Rider adjustment, which is more readily accomplished in the new model.

Q. Would you please explain the additional electric vehicle reporting line?

A. Yes. Minnesota Power recently received Commission approval for an Electric Vehicle Program (Docket No. E015/M-20-638) and for an Electric Vehicle Charger Infrastructure Project (Docket No. E015/M-21-257). The Company however did not receive approval for a cost recovery mechanism and is instead deferring those costs pending approval of a future cost recovery mechanism. A new reporting line for these deferred costs were created in CCOSS. However, since cost recovery has not been approved, all electric vehicle costs are pulled out of the 2022 test year budget as a rate making adjustment, as discussed by Company witness Ms. Turner.

Q. Please briefly discuss the refinement for handling contra AFUDC internal allocators.

A. As discussed in detail in MP Exhibit __ (Shimmin), Direct Schedule 1, prior to our 2016 Rate Case, contra AFUDC had been added to the CCOSS to reflect the implementation of a FERC directive (FERC Docket No. ER11/134-000). The contra AFUDC lines were added prior to our last rate case to Plant, Construction Work in Progress ("CWIP"), Accumulated Reserve, and Depreciation Expense. In implementing UIPlanner, Minnesota Power noted that Hydro Contra was being internally classified as all demand-related, even though a small portion of Hydro Plant is classified as energy-related. Minnesota Power therefore refined the internal allocators to ensure all contra accounts are functionalized and allocated following the associated rate base or income statement cost and that any change in the parent component will automatically be followed for contra accounts.

Q. Would you please briefly discuss the additional mapping of CWIP – Distribution?

A. In Minnesota Power's previous CCOSS, CWIP – Distribution was spread to sub-functions in the CCOSS based on ratios from Distribution – Plant. Distribution – CWIP is now mapped directly from source data, eliminating the need for spreading based on ratios.

Q. Would you please briefly discuss the elimination of internal allocators related to land?

A. The previous CCOSS had a number of internally generated allocators based on plant in-service balances less land. Because land was functionalized, classified, and allocated following the related plant-in-service, the resulting allocators were redundant and essentially the same as directly using allocators based on plant-in-service. They were therefore eliminated and replaced with allocators based on plant-in-service.

Q. Would you please briefly discuss the handling of actual data for prepayments?

A. In previous rate cases, the manual gathering of data included in the calculation of 13-month averages for the various prepayment accounts was carried out over a number of months as the rate case filing was being developed. This led to the risk of inconsistencies in the number of months that actual data was available and used among the various accounts. Now that the data is being pulled and directly mapped from source systems, the number of months of actual data is consistent and easily controlled.

Q. Would you please briefly summarize the refinements made to developing the income statement?

A. Minnesota Power has implemented changes in revenue details, how Other Operating Revenue credits are distributed, the sign of expenses, splitting distribution operation and maintenance ("O&M") expense, the allocation of transmission expenses, interest on customer deposits, labor only ratio for O&M expense fuel, internal allocators for contra

AFUDC, mapping of AFUDC, and a reclassification of Non-Fuel Clause Adjustment ("FAC") Energy Transactions from miscellaneous revenue to resale revenue.

Q. Would you please briefly discuss the change related to revenue details?

A. Yes. In Minnesota Power's previous CCOSS, revenue was input at a summarized level. The efficient data import and mapping functionality of UIPlanner allowed Minnesota Power to integrate more revenue details than in the past, such as rate schedule, classification, FERC account, and description field for each revenue item.

Q. Would you please briefly discuss the change to allocating Other Operating Revenue credits?

A. Other Operating Revenue that is functionalized to the distribution function is now allocated following the functionalization and classification of all distribution plant in service excluding contra. Previously, Other Operating Revenue credits were not allocated to Meters, Distribution Bulk Delivery, or Lighting. This refinement results in Other Operating Revenue credits being allocated across distribution plant in a more consistent manner.

Q. Would you please briefly discuss the change in the sign of expenses?

A. In Minnesota Power's previous CCOSS, income statement expenses had a positive sign and were subtracted by formula. In the new model, expenses now have a negative sign.

Q. Would you please briefly discuss the change in splitting Distribution O&M Expense?

A. Distribution O&M Expense was previously manually split between meters, distribution bulk delivery, and other distribution. This split is now directly mapped to meters and other distribution, which includes distribution bulk delivery.

Q. Would you please briefly discuss the change in allocating Transmission expenses?

A. Previously, Transmission expenses were allocated based on the external Demand Transmission ("DTRAN") allocator. These are now more accurately allocated using an internal allocator ("TPIS"), which follows the three components of transmission plant: transmission-production, transmission, and contra AFUDC.

Q. Would you please briefly discuss the change in allocating Interest on Customer Deposits?

A. Previously, Interest on Customer Deposits was allocated to both FERC and Minnesota jurisdictions on rate base and to retail class based only on Primary and Secondary Overhead line plant. To provide more consistent allocation, the retail portion is now also allocated on retail rate base.

Q. Would you please briefly discuss the change to the labor only ratio for O&M Expense Fuel?

A. As discussed in detail in MP Exhibit ___ (Shimmin), Direct Schedule 1, O&M Expense Labor Only ratios are used in a number of places in the CCOSS. In Minnesota Power's previous CCOSS, the values to determine the ratios were manually gathered and summarized into functional categories. The labor only values for O&M Expense Fuel were previously included with the labor only values for O&M Expense Steam. Because labor only cost types can now be directly mapped from source data exactly following O&M expense accounts, for consistency, the labor only value for fuel is now mapped separately and not included in Steam labor.

Q. Would you please briefly discuss the change in the internal allocators related to contra accounts?

A. As discussed above for rate base, Minnesota Power refined the internal allocators related to contra accounts, and this carried over to depreciation contra accounts on the income statement.

Q. Would you please briefly discuss the change to the mapping of AFUDC?

A. As discussed above for rate base, the benefit of direct mapping of CWIP carried over to the income statement, where CWIP is used to functionalize AFUDC.

Q. Would you please briefly discuss the reclassification of Non-FAC Energy Transactions?

A. To reflect a change in FERC reporting for certain energy transaction that do not flow through the FAC and to retain consistency of COSS treatment, Non-FAC Energy Transactions have been moved, or reclassified, from Miscellaneous Revenue to the Sales for Resale reporting line. The revenue continues to be allocated as energy-related, resulting in no net change to revenue requirements.

Q. Please summarize the Company's CCOSS model and results.

A. As discussed above, the Company is proposing two new allocation methodologies for production demand and transmission costs that result in fairer and more equitable overall revenue requirements by class. While the Company has made several beneficial refinements to its CCOSS model, our approach to the overall class cost of service model has not materially changed from prior rate cases in which our CCOSS results have been considered as part of the revenue allocation and rate design processes. Minnesota Power's current CCOSS presents reasonable results that are an appropriate basis for determining final rates in this proceeding.

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 cost of service studies: 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.

<u>Production</u>

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

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 all Production, Transmission, and 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 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 2019. As further described in 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 6, and the Distribution Plant Study is included in Volume 4, Workpapers and Studies, OS-1.

Table 6. Classification of Distribution Plant

Classification of Distribution Plant
Based Results of 2019 Distribution Plant Study

Plant	FERC Account *Function Code*	Function	Customer Classification Minimum System %	Demand Classification %
Poles , Towers	364, 365	Primary Overhead Lines	37.55%	62.45%
OH Conductors	*D300*	Secondary Overhead Lines	49.44%	50.56%
UG Conduits, &	366, 367	Primary Underground Lines	24.20%	75.80%
Conductors	*D400*	Secondary Underground Lines	10.43%	89.57%
Line	368	Overhead Transformers	26.34%	73.66%
Transformers	*D500*	Underground Transformers	49.38%	50.62%
Services	3691	Overhead Services	53.75%	46.25%
	3692	Underground Services	27.57%	72.43%
	D600			

Q. Please describe the allocation to classification.

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 name 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, 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.

Q. Were the classification methodologies developed using the same methodologies as in Minnesota Power's 2016 Rate Case?

A. Yes — apart from the overall minor refinements described above, the rate base and income statement are assigned to a classification using the same methodologies as in

Minnesota Power's 2016 Rate Case. However, the order of operation of the allocation to classification has changed in UIPlanner.

Q. Please briefly describe how the order of operation of the allocation to classification has changed in UIPlanner compared to Minnesota Power's 2016 Rate Case.

A. As previously discussed, Minnesota Power's previous Excel-based CCOSS model was built on underlying macros. In the Excel format, costs were manually input and could be allocated down by classification or directly assigned to a classification. When the model was run, the classified cost would then be allocated across jurisdiction and customer class. In contrast, UIPlanner is a flat modeling platform where allocations occur across the datasets rather than down. Therefore, prior to allocation across customer class, including the FERC jurisdiction, the costs must be allocated across to classification. So while the costs are classified to the same demand, energy, and customer classifications as in Minnesota Power's 2016 Rate Case, they are now first allocated across classifications in UIPlanner.

Q. Please describe the last step involved in the separation of 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 approved in Minnesota Power's last three rate cases before the Commission (Docket Nos. E015/GR-08-415, E015/GR-09-1151, and E015/GR-16-664), and the Company's last FERC wholesale rate case (FERC Docket No. ER08-397-000).

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

A Both Production-Demand and Transmission costs are allocated based on 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 jurisdictional separation of Distribution Bulk Delivery costs?

A Distribution Bulk Delivery 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 demands reflect the customer loads that are considered in designing the system and therefore are used for jurisdictional separation purposes. The separation is accomplished by aggregating the non-coincident demands of all FERC jurisdictional customers served from distribution bulk delivery points of output and separately aggregating such 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 demands.

Q. Would you explain the basis for the 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. The jurisdictional energy allocator was developed in the same manner as approved by the Commission in our 2016 Rate Case.

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 2020, 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 projected year 2021 and the 2022 test year use the same actual allocation ratios as 2020?

A. Yes. The projected year 2021 and the 2022 test year budgeted amounts were allocated using the 2020 ratios to determine 2021 and 2022 allocation factors. The jurisdictional separation of customer costs in the present filing follows the same procedures approved in Minnesota Power's last three completed retail rate cases (Docket No. E-015/GR-08-415, E-015/GR-09-1151, and E015/GR-16-664) 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 Minnesota Power's last rate case?

A. The comparison of the jurisdictional allocation factors is shown in MP Exhibit ___ (Shimmin), Direct Schedule 2 attached to my testimony. Please note the change in the allocator codes from the previous codes to the new codes in UIPlanner.

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. Volume 3, Schedule B-16 lists the rate base components by CCOSS reporting line and provides the jurisdictional allocator names/codes for each reporting line. Volume 3, Schedule B-17 provides the Total Company jurisdictional allocator bases by classification for the Unadjusted Most Recent Fiscal Year 2020, Unadjusted Projected Fiscal Year 2021, and Proposed Test Year 2022. Volume 3, Schedule B-18 provides the Minnesota Jurisdiction allocator bases by classification for the Unadjusted Most Recent Fiscal Year 2020, Unadjusted Projected Fiscal Year 2021, and Proposed Test Year 2022. Volume 3, Schedule B-19 provides the Minnesota Jurisdiction allocator factors by classification for the Unadjusted Most Recent Fiscal Year 2020, Unadjusted Projected Fiscal Year 2021, and Proposed Test Year 2022. Volume 3, Schedule C-13 lists the Operating Income components by CCOSS reporting line and provides the jurisdictional allocator names/codes for reporting line. Volume 3, 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 cost of service model. These allocation factors are generated based on one or more revenue, expense, or rate base items that have been allocated to jurisdiction and 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 five-year period, there have clearly been a number of changes in Minnesota Power’s operations, which have impacted the jurisdictional allocations since our 2016 rate case. Generally, the trend seen in demand and energy allocators from the 2017 test year through the 2022 test year reflects a combination of a number of changes that decreased Minnesota Power's non-retail load relative to the Company's retail load: 1) The Husky Refinery explosion and shutdown in mid-2018 caused a decrease in Superior Water Light & Power load, which is a firm Municipal customer; 2) in mid-2019, Minnesota Power lost Brainerd as a firm Municipal customer; 3) the COVID-19 pandemic's effect on customer energy sales; and 4) revised and extended contracts with several Minnesota Municipal customers reduced their firm load and energy. There have also been a number of changes that have decreased Minnesota Power's retail load: 1) the Verso paper mill shutdown; 2) the mid-2017 reduction in load at the Blandin paper mill; and 3) the COVID-19 pandemic's effect on customer energy sales, which are somewhat offset by increased sales through a non-firm retail supply agreement with Silver Bay Power Company. In addition, since our 2016 rate case, the Company has added Brainerd and Dahlberg as wheeling customers. The trend seen in the customer allocators C-13 and C-14 from the 2017 test year to the 2022 test year reflects internal reorganization and reduction in sales expenses.

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 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 and Studies, AF-1.

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 two new proposed methodologies discussed above.

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 2020, as well as from test year projected demands. In developing the distribution demand allocators, 2013 to 2014 load research results were used for the average demand contribution per customer for coincidental peak and non-coincidental peak. Refer to MP Exhibit ___ (Shimmin), Direct Schedule 1, Guide to Minnesota Power's CCOSS, and to Volume 4, Workpapers and Studies, AF-1.

(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. The analyses were based on the most recently available historical energy data from 2020, as well as from test year projected usage. For the last several Minnesota Power rate cases, we have utilized the E8760 energy allocator to allocate energy costs to customer classes.[10] In developing the E8760 energy allocator, 2013 to 2014 load research results on the annual hourly load shapes were used in scaling 2022 test year budgeted energy. Refer to Exhibit ___ (Shimmin), Direct Schedule 1, Guide to Minnesota Power's CCOSS, and to Volume 4, Workpapers and Studies, AF-1.

(c) <u>Customer allocation factors analyses</u>—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

[10] This history and development of the E8760 allocator is discussed in the Guide to the CCOSS at p. 4.

recently available historical data from 2020, actual data through June 2021, projected data from July to December 2021, as well as from 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 and Studies, AF-1.

(d) <u>Distribution Plant Study, including minimum-system</u>—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 2016 rate case and is based on analyses of 2018 data and field conditions. The report is included in Volume 4, Workpapers and Studies, OS-1.

(e) <u>Lead-Lag Study</u>—Revenue lead days and expense lag days from the 2019 Lead-Lag Study were utilized in estimating test year cash working capital. The Lead-Lag Study was developed based on 2019 data. The report is included in Volume 4, Workpapers and Studies, OS-2.

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

A. In addition to the two new allocation methodologies, the Company is using customary practices to allocate costs among customer classes, which result in reasonable overall costs 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 riders going forward.

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.[11]

Q. Has Minnesota Power complied with Order Point 47 from the Commission's Order in the last rate case related to 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 will no longer be recovered in a rider. Minnesota Power is excluding from the rate case all project costs that will continue to be recovered in riders.

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

A. Minnesota Power is currently using the following cost recovery riders:

- Transmission Cost Recovery ("TCR") Rider;
- Renewable Resources Rider ("RRR");
- Solar Factor under Renewable Resources Rider ("SRRR");
- Rider for 2017 Federal Tax Cut Refund;
- Fuel and Purchased Energy Rider (discussed by Company witness Ms. Peterson); and
- Conservation Program Adjustment (discussed by Company witness Ms. Peterson).

[11] 2016 Rate Case Order at 112.

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

A. Yes. Table 7 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.

Table 7. Summary of Rider Treatment in 2022 Test Year

Transmission Cost Recovery Rider	
Moving to Base Rates	**Staying in the Rider**
Dog Lake Project	Great Northern Transmission Line ("GNTL") Project
	Regional Expansion Criteria and Benefits ("RECB") Net Expense/Revenue and Credit for MISO Multi-Value Projects Revenue
Renewable Resources Rider (RRR)	
Moving to Base Rates	**Staying in the Rider**
Final two Thomson Hydroelectric Projects	Production Tax Credit True-up
Large Generator Interconnection Agreement Credit	
Credit for Oconto Renewable Energy Credits	
Solar Factor (under RRR)	
Moving to Base Rates	**Staying in the Rider**
	Camp Ripley
	Community Solar Garden
	SolarSense Program
Rider for 2017 Federal Tax Cut Refund	
Moving to Base Rates	**Staying in the Rider**
Excess Accumulated Deferred Income Taxes ("Excess ADIT")	
Close out rider with Interim 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 items: (1) the Great Northern Transmission Line Project ("GNTL") (Docket

Nos. E015/CN-12-1163 and E015/TL-14-21*)*; (2) RECB net revenue and expenses; and (3) MISO new transmission facility net revenues or expenses.

Q. Why does the Company propose to continue to recover costs for GNTL in the TCR Rider?

A. Minnesota Power proposes to continue to recover these costs in the TCR Rider for two main reasons. First, the Company's 2021 TCR Factor Filing (Docket No. E015/M-20-900) is currently being considered by the Commission, and there is uncertainty as to the timing of an eventual Commission order in that docket. As the Company reached the timeline to lock down assumptions for the rate case, it was not feasible to move these costs into base rates without a Commission decision on the 2021 TCR Factor Filing. The second reason is due to the relatively large tracker balance in the TCR. The Company decided it would be better to move GNTL costs into base rates after the relatively large TCR tracker balance is reduced. Thus, the Company proposes to roll GNTL costs into base rates in a future rate case after the 2021 TCR Factor Filing has been implemented and the tracker balance has been reduced.

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

A. The MISO new 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") that Minnesota Power is not an owner of but is allocated a portion of the costs and revenues as a MISO member. Minnesota Power will continue providing a credit in the TCR Rider for the MVP revenues it receives.

Q. What TCR charges does Minnesota Power propose to roll into base rates?

A. Minnesota Power proposes to include in base rates costs related to the Motley-Area 115 kV Transmission Line Project (also referred to as the "Dog Lake Project") for which the Commission approved a certificate of need and route permit on March 23, 2016 (Docket Nos. ET2, E015/CN-14-853 and ET2, and E015/TL-15-204). The Dog Lake

Project is a joint project with Great River Energy and was fully energized and placed in service in 2017. Minnesota Power proposes to include the Company's share of the actual total costs for the Dog Lake Project in base rates. Company witness Mr. Gunderson discusses the prudency of the costs associated with this project and why it is appropriate for the Company to recover its share of the costs for the Dog Lake Project.

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. Specifically, Minnesota Power proposes to include, as required by Order Point 37 from the Company's 2016 Rate Case, an annual true-up of actual production tax credits ("PTC") generated by the Bison Wind Projects that are currently in base rates. This true-up now also includes the PTC generated by the Company's Taconite Ridge wind facilities.

Q. What RRR charges will be rolled into base rates?

A. Minnesota Power proposes to roll into base rates costs related to the two remaining projects of the Thomson Hydroelectric Restoration Project and reimbursement related to the transfer of a Large Generator Interconnection Agreement ("LGIA") to Minnesota Power's affiliate ALLETE Clean Energy, Inc. ("ACE"). For the Thomson Hydroelectric projects, the last of which was completed in 2018, Minnesota Power proposes to include the actual cost for these projects in base rates. Company witness Todd Z. Simmons discusses these costs and why it is appropriate for the Company to recover its investments in the two remaining projects to restore the Thomson Hydroelectric facility.

Q. Can you provide an overview of the LGIA credit in the RRR?

A. Minnesota Power is proposing to roll the LGIA Credit currently in the RRR into base rates. Minnesota Power filed its Affiliate Interest Agreement petition between ALLETE, Inc. and ACE with the Commission on April 19, 2017, seeking approval to transfer the Bison 6 LGIA to ACE. At the time, Minnesota Power recommended crediting customers for certain costs related to the transfer through the RRR to facilitate the most expedient reimbursement since Minnesota Power was in the midst of the regulatory review process for its 2016 Rate Case. Since customers were paying the costs for assets being transferred to ACE, the March 16, 2018 Order in Docket No. E015/AI-17-304 required Minnesota Power to reimburse customers for:

- Bison 6's share of capital costs spent on the transmission line and related facilities supporting the Bison 6 LGIA;
- The revenue requirements — both return on equity and depreciation — from Bison 6's share of transmission costs allocated to ACE; and
- Bison 6's share of costs to operate and maintain the transmission facilities.

Q. How does Minnesota Power propose to handle the LGIA in the 2022 test year?

A. Minnesota Power is proposing to meet the same requirements established in Docket No. E015/AI-17-304 but would like to roll the credit into base rates. The payment from ACE for its share of the capital costs that Minnesota Power had incurred for the transmission line and related facilities supporting the interconnection was received in 2019. Minnesota Power reduced its plant in-service for the payment in 2019. Therefore, the 2022 test year plant in-service reflects this reduction. This ensures customers are not paying for those costs. Additionally, reflecting the payment from ACE to Minnesota Power for its share of the related O&M will effectively reduce the amount of O&M for which Minnesota Power's customers are responsible. Minnesota Power has included this payment from ACE in the 2022 test year budget.

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 implementation of billing factors to recover the costs related to Minnesota Power's Camp Ripley Solar project, Community Solar Garden projects, and SolarSense program.[12] 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

[12] *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).

from paying costs to meet the SES. Because of this, all solar-related revenues and costs are excluded from the 2022 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. What does Minnesota Power propose with respect to the Rider for Federal Tax Cut Refund?

A. Late in Minnesota Power's 2016 rate case, the Tax Cut and Jobs Act ("TCJA") was enacted. The Company was able to incorporate the lower tax rate into the (2017) test year but was unable to incorporate the tax impacts on Excess Accumulated Deferred Income Taxes ("Excess ADIT"). Instead, the Rider for Federal Tax Cut Refund was established and customers have been receiving a credit on their bills. In the present rate case, the Company is proposing to incorporate the Excess ADIT into base rates. With the tax benefit also incorporated into the proposed January 1, 2022 interim rates, the Company proposes to zero-out the rider in order to avoid double-counting the Excess ADIT.

Q. Has the 2022 test year been adjusted in order 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 2022 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 and Studies, ADJ-RB-10 and ADJ-IS-23.

VII. CONCLUSION

Q. Does this complete your testimony?

A. Yes.

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

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

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

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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.

The Company is proposing two new methodologies for allocating production-demand costs and transmission costs. These are discussed in Direct Testimony of Company witness Mr. Stewart J. Shimmin, and are not reflected below.

Otherwise all functionalization, classification, and allocation methodologies presented in this guide are the generally the same as the Minnesota Public Utilities Commission ("MPUC" or "Commission") considered in Minnesota Power's last rate case, Docket E015/GR-16-664 ("2016 Rate Case"). Minor changes and refinements since the last rate case are discussed in Direct Testimony of Company witness Mr. Shimmin and are reflect 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.

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 three retail rate cases. (Docket Nos. E015/GR-08-415, E015/GR-09-1151, and E015/GR-16-664). 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 three 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 Peak & Average (P&A) methodology as described below.

In four retail rate cases from 1980 to 1994, Minnesota Power developed its Production and Transmission retail class allocation factors on the Average and Excess/Probability of Deficiency ("A&E/POD") methodology, or CAPSUBPOD as it was often called. After Minnesota Power's 1994 rate case, the computer platform on which this program ran was replaced, rendering the program obsolete. Because the consultant that developed and updated the program was no longer available prior to Minnesota Power's subsequent 2008 rate case, it was necessary to develop a new methodology.

In the Company's 1980 rate case (Docket No. E015/GR-80-76), the Minnesota Department of Public Service, (now the Department of Commerce, Division of Energy Resources), recommended the P&A methodology as an alternative to the CAPSUBPOD methodology. The Peak & Average methodology was recommended "because it does a reasonably good job of allocating the revenue requirements to the various classes and it is also understandable and a reasonably straight forward method."[1] In addition, the methodology results in allocation factors that are very similar to those developed using Minnesota Power's historic methodology, the CAPSUBPOD method. Based on these considerations, Minnesota Power selected the Peak & Average (P&A) methodology as the basis for developing the Production and Transmission allocation factors. This methodology was subsequently used, approved, or considered by the MPUC in Minnesota Power's last three retail rate cases.

The P&A methodology allocates fixed production and transmission costs to class based on a composite allocation factor that is composed of two parts – 1) an average demand (or energy) and 2) a coincidental peak. Similar to the traditional Average and Excess method and other energy weighting methods, all plant costs may remain classified as demand-related despite the use of a

[1] *In the Matter of the Petition of Minnesota Power and Light Company for Authority to Change its Schedule of Rates for Electric Service Furnished to its Customers in the State of Minnesota*, Docket No. E015/GR-80-76 DIRECT TESTIMONY OF PHILLIP ZINS at 29 (July 11, 1980).

composite average demand (energy)/CP demand allocator. NARUC Manual (Chapter 4) characterizes these methods as "partial energy weighing methods."

The initial step is accomplished by the P&A 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 P&A allocator allocates the balance of the costs on each class's proportional contribution to coincidental peak (CP). The composite allocator can be shown as follows:

$$\text{Composite Allocation Factor} = \text{LF} \times (\text{Average Demand Factor}) + (100 - \text{LF}) \times (\text{CP Demand Factor})$$

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

C. <u>Hydro Plant: FERC Accounts 330-336</u>

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

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

<u>Hydro Production – Demand</u> is allocated to customer class following the same methodologies as described above for the Production - Demand function.

<u>Hydro Production – Energy</u> 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 three 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.

<u>Hydro Production - Energy</u> 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 three 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 two 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 P&A method for retail class allocations.

This treatment of wind plant was approved in Minnesota Power's three last 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 P&A 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 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 methodologies as described above for the Production - Demand function.

Costs functionalized to Transmission are allocated to jurisdiction based on the 12-month average coincident peak (12CP) method and to retail classes using the P&A method, both calculated at the transmission level. Refer to Steam Plant above for explanation of 12CP and P&A methodologies. This treatment of transmission plant was approved in Minnesota Power's three last retail rate cases and is consistent with the method approved in Minnesota Power's Transmission Cost Recovery Rider.

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

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

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 three 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 three retail rate cases and are also consistent with the NARUC Manual's classification of sub-transmission (distribution bulk delivery) facilities (Chapter 6, pages 87 and 90).

Demand and Customer Related

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

The above classifications are consistent with Minnesota Power's last three 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 2019 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 2019 Distribution Plant Study in Volume 4, Workpapers.

D660 Distribution – Customer Premises – EV Charger is a new line item that hold the new EV Charger project. As discussed in Direct Testimony of witness Mr. Shimmin, all costs related to EV Charger project are excluded from the Test Year CCOSS because they have not received Commission approval for cost recovery.

Table 2
Classification of Distribution Plant
Based Results of 2019 Distribution Plant Study

Plant	FERC Account *Function Code*	Function	Customer Classification Minimum System %	Demand Classification %
Poles , Towers	364, 365	Primary Overhead Lines	37.55%	62.45%
OH Conductors	*D300*	Secondary Overhead Lines	49.44%	50.56%
UG Conduits, &	366, 367	Primary Underground Lines	24.20%	75.80%
Conductors	*D400*	Secondary Underground Lines	10.43%	89.57%
Line	368	Overhead Transformers	26.34%	73.66%
Transformers	*D500*	Underground Transformers	49.38%	50.62%
Services	3691	Overhead Services	53.75%	46.25%
	3692	Underground Services	27.57%	72.43%
	D600			

Customer Related

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

The above classifications are consistent with Minnesota Power's last three 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.

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		Meters & cost	-	Meters & cost
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.

2/ Distribution Bulk Delivery are 23, 34 and 46 kV facilities that serve FERC and retail jurisdictional customers.

3/ Specific Distribution 14 kV facilities and 23, 34, and 46 kV taps that serve FERC jurisdictional customers.

Meter costs are incurred to serve customers in both Minnesota Power's FERC and retail jurisdictions, thus, it is necessary to 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 meter allocator (CC-DSMETERS).

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

Step-up transformers at generating stations recorded in distribution plant are sub-functionalized to production-demand and are allocated between jurisdictions based on the 12CP method following the method described above for 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. Meter costs are allocated to class as described above (CC-DSMETERS).

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 three 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. General Plant: FERC Accounts 389-399

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

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

This treatment is consistent with Minnesota Power's last three 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 tree 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 three 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 three 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 three 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 three 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 three 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 three 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 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 three 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 three 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 based on the 12CP method and to class based on the P&A method described above for Transmission – Demand function (CC-TRAN).

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 based on the 12CP method and to class based on the P&A method described above for Transmission – Demand function (CC-TRAN).

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 P&A 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 three 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 P&A 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 three 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 P&A 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 P&A 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 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 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 P&A 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 P&A 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 P&A 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 three 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).

In Minnesota Power's last three rate cases these expenses were allocated on the external CC-TRAN Transmission allocator. With the implementation of the UIP, these expenses are now more accurately allocated on a new internal allocator (TPIS) that follows the three components of transmission plant: production, transmission, and AFUDC contra.

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

O&M expenses – Distribution – Meters are classified as customer related 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 follows the NARUC Manual (Chapter 6, page 96).

These expenses are allocated to jurisdiction and class using the Customer Meter allocation factor (CC-DSMETERS) that is based on meter counts and costs as described above for meter plant.

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, this split in now 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 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 38).

These expenses are allocated to jurisdiction based on the 12CP method and to class based on the P&A 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 three 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 P&A 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 three 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 three 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 Account Credit Cards: FERC Sub-Account 90300.1000

O&M Expenses – Customer Account Credit Cards are classified as customer-related consistent with the above primary account. The expenses for this new service are allocated only to Minnesota jurisdiction reflecting the actual retail credit card processing fees from October 2018 until August 2019. These fees by applicable rate code were assigned to the appropriate class to develop the Customer Account allocator (CC-OMCC).

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

O&M Expenses – Customer Service and Information are classified as customer related consistent with the approach approved in Minnesota Power's last three 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.

T. 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.

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

O&M Expenses – Sales are classified as customer-related consistent with the approach approved in Minnesota Power's last three 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.

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

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

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

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

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

O&M Expenses – Regulatory Expenses - MISO are functionalized to Transmission and are allocated to jurisdiction based on the 12CP method and to class based on the P&A method described above for Transmission function. This treatment is 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.

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

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

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

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

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

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

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

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

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

DD. Depreciation Expense: FERC Account 403

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

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

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

FF. UMWI Amortization Expense: FERC Accounts 406, 407.3

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

GG. ARO Accretion Expense: FERC Account 411.1

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

HH. 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.

II. Rate Case Expense Amortization: FERC Account 928

Rate case expense amortization is functionalized, classified, and allocated following total retail rate base. This is consistent with the approach approved in Minnesota Power's last three retail rate cases and consistent with the methodology approved in Minnesota Power's last FERC rate case.

JJ. Property Taxes: FERC Account 408.1

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

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

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

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

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

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

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

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

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

NN. State Current Income Tax

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

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

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

OO. 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.

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

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

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

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

SS. Operation & Maintenance Expense – Labor Only

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

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

This treatment is consistent with the approach approved in Minnesota Power's last three 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	P & A	(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	P & A	(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	P & A	(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	P & A	(E)	CC-PROD
15	TRANSMISSION										
16	TRANSMISSION PRODUCTION	C200	3/	C-TPIS	X	-	-	12 CP	P & A	(E)	CC-PROD
17	TRANSMISSION	350-359		C-TPIS	X	-	-	12 CP	P & A	(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	Meter Counts & Cost		(E)	CC-DSMETERS
42	PRODUCTION - DEMAND	D200	5/	C-DOPROD	X	-	-	12 CP	P & A	(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-DODBDSA	X	-	-	Direct	-	(E)	CC-DODBDSA
46	DIST PRIMARY SPECIFIC ASSIGN	various		C-DODPSA	X	-	-	Direct	-	(E)	CC-DODPSA
47	DISTRIBUTION CONTRA			C-DPPIS	X	-	X	Direct	-	(I)	CC-DPPIS
48	GENERAL PLANT										
49	GENERAL PLANT	389-399		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(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/
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	P & A	(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	P & A	(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	P & A	(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	P & A	(E)	CC-PROD
67	TRANSMISSION										
68	TRANSMISSION PRODUCTION	107		C-TCWIP	X	-	-	12 CP	P & A	(E)	CC-PROD
69	TRANSMISSION	107		C-TCWIP	X	-	-	12 CP	P & A	(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	Meter Counts & Cost		(E)	CC-DSMETERS
94	PRODUCTION - DEMAND	107		C-DOPROD	X	-	-	12 CP	P & A	(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
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										

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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	P & A	(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	P & A	(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	P & A	(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	P & A	(E)	CC-PROD
118	TRANSMISSION										
119	TRANSMISSION PRODUCTION	108, 110		C-TPIS	X	-	-	12 CP	P & A	(E)	CC-TPISXCONTRA
120	TRANSMISSION	108, 110		C-TPIS	X	-	-	12 CP	P & A	(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	Meter counts & cost		(E)	CC-DSMETERS
145	PRODUCTION - DEMAND	108, 110		C-DOPROD	X	-	-	12 CP	P & A	(E)	CC-PROD
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

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/
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	P & A	(E)	CC-PROD
160	TRANSMISSION	154, 163		C-TPIS	X	-	-	12 CP	P & A	(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	Meter Counts & Cost		(E)	CC-DPIS
183	PRODUCTION - DEMAND	154, 163		C-DPIS	X	-	-	12 CP	P & A	(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
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/								

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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/
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	SALES TAX COLLECTIONS	-		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLXAG
203	INCOME TAXES	-		C-RATEBASE	X	X	X	Rate Base		(I)	CC-RATEBASE
204	INCOME TAXES (INCREASE)	-		C-RATEBASE	X	X	X	-	Rate Base	(I)	CC-RATEBASEMN
205	**ASSET RETIREMENT OBLIGATION**	23000, 18230		C-STEAM	X	-	-	12 CP	P & A	(E)	CC-PROD
206	**ELECTRIC VEHICLE PROGRAM**	18640.0553		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
207	**WORKERS COMP DEPOSIT**	18640.0093		C-OMLXAG	X	X	X	Total O&M Labor Excl A&G		(I)	CC-OMLAXAG
208	**UNAMORTIZED WPPI TRANSM AMORT**	25300.9030		C-WPPI	X	-	-	12 CP	P & A	(E)	CC-TPIS
209	**UNAMORTIZED UMWI TRANSACTION COST**	18230.3003		C-UMWI	X	-	-	12 CP	P & A	(E)	CC-TPIS
210	**UNAMORTIZED BOS 1 and 2**	18230.3011/13		C-STEAM	X	-	-	12 CP	P & A	(E)	CC-PROD
211	**CUSTOMER ADVANCES**										
212	PRIMARY OVHD LINES - DEM	252		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
213	PRIMARY OVHD LINES - CUST	252		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
214	SECONDARY OVHD LINES - DEM	252		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
215	SECONDARY OVHD LINES - CUST	252		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
216	**CUSTOMER DEPOSITS**	235		C-ADVANCES	X	-	X	Total Customer Advances		(I)	CC-ADVANCES
217	**OTHER DEFERRED CREDITS - HIBBARD**	25300.9058/9		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
218	**WIND PERFORMANCE DEPOSIT**	25300.9091		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
219	**ACCUMULATED DEFERRED INCOME TAXES**										
220	STEAM - Cr	281-3		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
221	HYDRO - Cr	281-3		C-HYDRO	X	X	-	Hydo PIS		(I)	CC-HYDRO
222	WIND - Cr	281-3		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
223	SOLAR - Cr	281-3		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
224	TRANSMISSION - Cr	281-3		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
225	DISTRIBUTION - Cr	281-3		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
226	GENERAL - Cr	281-3		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
227	STEAM - Dr	190		C-STEAM	X	-	-	Steam PIS		(I)	CC-STEAM
228	HYDRO - Dr	190		C-HYDRO	X	X	-	Hydo PIS		(I)	CC-HYDRO
229	WIND - Dr	190		C-WIND	X	-	-	Wind PIS		(I)	CC-WIND
230	SOLAR - Dr	190		C-SOLAR	X	-	-	Solar PIS		(I)	CC-SOLAR
231	TRANSMISSION - Dr	190		C-TPIS	X	-	-	Transmission PIS		(I)	CC-TPIS
232	DISTRIBUTION - Dr	190		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
233	GENERAL - Dr	190		C-OMLXAG	X	X	X	General PIS		(I)	CC-OMLXAG
234											
235	**OPERATING INCOME**										
236	**OPERATING REVENUES**										
237	REVENUE FROM SALES BY RATE CLASS AND DUAL FUEL										
238	SALES BY RATE CLASS	440-447		C-RSALES	X	X	X	Direct	Direct	(I)	CC-RSALES
239	DUAL FUEL DEMAND	440-443		C-RDUALFUEL	X	-	-	-	P & A	(E)	CC-PRODMN
240	DUAL FUEL ENERGY	440-443		C-RDUALFUEL	-	X	-	-	E8760	(E)	CC-PRODMN
241	OTHER REVENUE FROM SALES										
242	INTERSYSTEM SALES DEMAND	443		C-RISSALES	X	-	-	12 CP	P & A	(E)	CC-PROD

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243	INTERSYSTEM SALES ENERGY	443		C-RISSALES	-	X	-	E-01	E8760	(E)	CC-PROD
244	LP DEMAND RESPONSE	443		C-DEMAND	X	-	-	-	P & A	(E)	CC-PRODMN
245	SALES FOR RESALE DEMAND	447		C-RRESALE	X	-	-	12 CP	P & A	(E)	CC-PROD
246	SALES FOR RESALE ENERGY	447		C-RRESALE	-	X	-	E-01	E8760	(E)	CC-PROD
247	OTHER OPERATING REVENUE (OOR)										
248	ORR - PRODUCTION DEMAND	454, 456.1, 456.4		C-RPROD	X	-	-	12 CP	P & A	(E)	CC-PROD
249	ORR - PRODUCTION ENERGY	456.9		C-RPROD	-	X	-	E-01	E8760	(E)	CC-PROD
250	ORR - TRANSMISSION	454, 456.2, 456.6, 456.9		C-TPIS	X	-	-	12 CP	P & A	(E)	CC-TPIS
251	ORR - DISTRIBUTION	450, 456.9									
252	DISTRIBUTION - PRIMARY										
253	OVERHEAD LINES - DEMAND	450, 456.9		C-DPOHL	X	-	-	-	Class NCP	(E)	CC-DPOHL
254	OVERHEAD LINES - CUSTOMER	450, 456.9		C-DPOHL	-	-	X	-	Customers	(E)	CC-DPOHL
255	UNGRD LINES - DEMAND	450, 456.9		C-DPUGL	X	-	-	-	Class NCP	(E)	CC-DPUGL
256	UNGRD LINES - CUSTOMER	450, 456.9		C-DPUGL	-	-	X	-	Customers	(E)	CC-DPUGL
257	DISTRIBUTION - SECONDARY										
258	OVHD LINES - DEMAND	450, 456.9		C-DSOHL	X	-	-	-	Sum NCP	(E)	CC-DSOHL
259	OVHD LINES - CUSTOMER	450, 456.9		C-DSOHL	-	-	X	-	Customers	(E)	CC-DSOHL
260	UNGRD LINES - DEMAND	450, 456.9		C-DSUGL	X	-	-	-	Sum NCP	(E)	CC-DSUGL
261	UNGRD LINES - CUSTOMER	450, 456.9		C-DSUGL	-	-	X	-	Customers	(E)	CC-DSUGL
262	OVHD LINE TRANSFRM - DEMAND	450, 456.9		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSOHT
263	OVHD LINE TRANSFRMS - CUSTOMER	450, 456.9		C-DSOHT	-	-	X	-	Customers	(E)	CC-DSOHT
264	UNGRD LINE TRANSFRMS - DEMAND	450, 456.9		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	CC-DSUGT
265	UNGRD LINE TRANSFRMS - CUSTOMER	450, 456.9		C-DSUGT	-	-	X	-	Customers	(E)	CC-DSUGT
266	OVHD SERVICES - DEMAND	450, 456.9		C-DSOHS	X	-	-	-	Sum NCP	(E)	CC-DSOHS
267	OVERHEAD SERVICES - CUSTOMER	450, 456.9		C-DSOHS	-	-	X	-	Customers	(E)	CC-DSOHS
268	UNGRD SERVICES - DEMAND	450, 456.9		C-DSUGS	X	-	-	-	Sum NCP	(E)	CC-DSUGS
269	UNGRD SERVICES - CUSTOMER	450, 456.9		C-DSUGS	-	-	X	-	Customers	(E)	CC-DSUGS
270	LEASED PROPERTY	450, 456.9		C-DSLEASED	-	-	X	-	Direct	(E)	CC-DSLEASED
271	STREET LIGHTING	450, 456.9		C-DSLIGHTING	-	-	X	-	Direct	(E)	CD-DSLIGHTING
272	DISTRIBUTION OTHER										
273	METERS	450, 456.9		C-DSMETERS	-	-	X	Meter Counts & Cost		(E)	CC-DSMETERS
274	PRODUCTION - DEMAND	450, 456.9		C-DOPROD	X	-	-	12 CP	P & A	(E)	CC-PROD
275	DISTRIBUTION BULK DELIVERY	450, 456.9		C-DODBD	X	-	-	NCP	Class NCP	(E)	CC-DODBD
276	DISTRIBUTION SUBSTATIONS	450, 456.9		C-DODSUB	X	-	-	-	Class NCP	(E)	CC-DODSUB
277	DIST BULK DEL SPECIFIC ASSIGN	450, 456.9		C-DODBDSA	X	-	-	Direct	-	(E)	CC-DODBDSA
278	DIST PRIMARY SPECIFIC ASSIGN	450, 456.9		C-DODPSA	X	-	-	Direct	-	(E)	CC-DODPSA
279	GENERAL PLANT	450, 456.9		C-OMLXAG	X	X	X	General Plant		(I)	CC-OMLXAG
280	ORR - DISPOSITION OF ALLOWANCES	411.8		C-RDISPALL	-	X	-	-	E8760	(E)	CC-PRODMN
281	ORR - CONSERVATION IMPROV PROGRAM	456.9		C-ENERGY	-	X	-	-	CCRC MWh	(E)	CC-CIP
282	ORR - RENEWABLE RESOURCES RIDER	456.9		C-RRR	X	X	-	12 CP	P & A	(E)	CC-RRR
283	ORR - SOLAR RENEWABLE RESOURCES RIDER	456.9		C-SRRR	-	X	-	12 CP	P & A	(E)	CC-SRRR
284	ORR - TRANSMISSION COST RECOVERY RIDER	456.9		C-TCR	X	X	-	12 CP	P & A	(E)	CC-TCR
	ORR - ELECTRIC VEHICLE PROGRAM	456.9		C-DPIS	X	-	X	Distribution PIS		(I)	CC-DPIS
285	**OPERATION & MAINTENANCE EXPENSE**										
286	STEAM PRODUCTION										
287	DEMAND	500-3, 505/6, 511, 514		C-OMSTEAM	X	-	-	12 CP	P & A	(E)	CC-PROD
288	ENERGY	510, 512-3		C-OMSTEAM	-	X	-	E-01	E8760	(E)	CC-PROD
289	HYDRO PRODUCTION										
290	DEMAND	535, 537-9, 541-2		C-OMHYDRO	X	-	-	12 CP	P & A	(E)	CC-PROD
291	ENERGY	543-5		C-OMHYDRO	-	X	-	E-01	E8760	(E)	CC-PROD

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292	WIND PRODUCTION	546-554		C-OMWIND	X	-	-	12 CP	P & A	(E)	CC-PROD
293	TRANSMISSION	560-2, 565-571, 573		C-TPIS	X	-	-	12 CP	P & A	(I)	CC-TPIS
294	DISTRIBUTION										
295	METERS	586, 597		C-DSMETERS	-	-	X	Meter Counts & Cost		(E)	CC-DSMETERS
296	OTHER DISTRIBUTION	580-5, 587-590, 592-8		C-DPISXMETERS	X	-	X	Dist PIS, Excl Meters		(I)	CC-DPISXMETERS
297	OTHER POWER SUPPLY										
298	PRODUCTION DEMAND	556-7		C-POWER	X	-	-	12 CP	P & A	(E)	CC-PROD
299	PURCHASED POWER										
300	DEMAND	555		C-PPOWER	X	-	-	12 CP	P & A	(E)	CC-PROD
301	ENERGY	555		C-PPOWER	-	X	-	E-01	E8760	(E)	CC-PROD
302	FUEL	501		C-ENERGY	-	X	-	E-01	E8760	(E)	CC-PROD
303	CUSTOMER ACCOUNTING	901-4		C-CUSTOMER	-	-	X	Expenses & Labor ratios		(E)	CC-OMACCOUNT
304	CUSTOMER ACCOUNTING CREDIT CARDS	903.1		C-CUSTOMER	-	-	X	Expenses & Labor ratios		(E)	CC-OMCC
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	P & A	(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	P & A	(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	P & A	(E)	CC-HYDRODE-C
322	WIND	403		C-HYDRO	X	-	-	Wind PIS		(E)	CC-PROD
323	WIND CONTRA			C-HYDRO	X	-	-	Direct	P & A	(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	P & A	(E)	CC-TDE-C
327	DISTRIBUTION	403		C-DADCONTRA	X	-	X	Distribution PIS		(E)	CC-DADCONTRA
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
333	UMWI	406, 407.3		C-UMWI	X	-	-	12 CP	P & A	(E)	CC-PROD
334	ARO ACCERTION	411.1		C-STEAM	X	-	-	12 CP	P & A	(E)	CC-PROD
335	BOSWELL 1 AND 2	40730.11		C-STEAM	X	-	-	12 CP	P & A	(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

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/
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**										
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	P & A	(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	P & A	(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
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	P & A	(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

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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										
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
438	**PROVISION FOR DEFERRED INCOME TAX - CREDIT**										
439	ACCOUNT 411.1										
440	STEAM	411.1		C-STEAM	X	-	-		Steam PIS	(I)	CC-STEAM

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

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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 subfunctionalized 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 subfunctionalized as production demand.
6/ Distribution Bulk Delivery are 23, 34 and 46 kV facilities that serve FERC and retail jurisdictional customers.
7/ Specific Distribution 14 kV facilities and 23, 34, and 46 kV taps that serve FERC jurisdictional customers.
8/ Subfunctionalized to production, transmission and distribution on most recent calender year actual amounts. Distribution subsequently subfunctionalized/classifed on PIS ratios.
9/ Calculated
10/ Calculated as part of interest syncronization. Average rate base multiplied by cost of long term debt.
11/ Refer to Volume 3, Direct Schedules E-3, Part 5a, 5b, and Part 6a, 6B for the classifcation allocators, bases and factors.
12/ Refer to Volume 3, Direct Schedules E-3, Part 7a, 7b, 7c and Part 8a, 8b for the customer allocators, bases and factors.

Comparison of Minnesota Jurisdictional Factors

Previous Allocation Code	New UI Allocation Code	Description	Final Ordered Projected Test Year 2017 Docket No. E015/GR-16-664	2020 Actual	2021 Projected	2022 Unadjusted Test Year Docket No. E015/GR-21-335	2022 Adjusted Test Year Docket No. E015/GR-21-335
Demand			(1)	(2)	(3)	(4)	(4)
D01	CC-PROD	Power Supply Production	84.36%	86.89%	86.32%	87.92%	87.92%
D02	CC-TRAN	Power Supply Transmission	82.71%	82.77%	82.16%	81.65%	81.65%
D03	CC-DODBD	Distribution Bulk Delivery	76.77%	71.41%	71.37%	71.72%	71.72%
D04	CC-DODSUB	Distribution Substations	100.00%	100.00%	100.00%	100.00%	100.00%
D05	CC-DPOHL	Primary Overhead Lines	100.00%	100.00%	100.00%	100.00%	100.00%
D06	CC-DSOHL	Secondary Overhead Lines	100.00%	100.00%	100.00%	100.00%	100.00%
D07	CC-DPUGL	Primary Underground Lines	100.00%	100.00%	100.00%	100.00%	100.00%
D08	CC-DSUGL	Secondary Underground Lines	100.00%	100.00%	100.00%	100.00%	100.00%
D11	CC-DSOHT	Overhead Line Transformers	100.00%	100.00%	100.00%	100.00%	100.00%
D12	CC-DSUGT	Underground Line Transformers	100.00%	100.00%	100.00%	100.00%	100.00%
D14	CC-DSOHS	Overhead Services	100.00%	100.00%	100.00%	100.00%	100.00%
D15	CC-DSUGS	Underground Services	100.00%	100.00%	100.00%	100.00%	100.00%
Energy							
E01	CC-PROD	Power Supply Production	84.31%	84.47%	84.38%	85.70%	85.70%
CIPEXPE	CC-CIP	Conservation Improvement Program Expense	100.00%	100.00%	100.00%	100.00%	100.00%
Customer							
C01	CC-DPOHL	Primary Overhead Lines	100.00%	100.00%	100.00%	100.00%	100.00%
C02	CC-DPUGL	Primary Underground Lines	100.00%	100.00%	100.00%	100.00%	100.00%
C03	CC-DSOHL	Secondary Overhead Lines	100.00%	100.00%	100.00%	100.00%	100.00%
C04	CC-DSUGL	Secondary Underground Lines	100.00%	100.00%	100.00%	100.00%	100.00%
C05	CC-DSOHT	Overhead Line Transformers	100.00%	100.00%	100.00%	100.00%	100.00%
C06	CC-DSUGT	Underground Line Transformers	100.00%	100.00%	100.00%	100.00%	100.00%
C07	CC-DSOHS	Overhead Services	100.00%	100.00%	100.00%	100.00%	100.00%
C08	CC-DSUGS	Underground Services	100.00%	100.00%	100.00%	100.00%	100.00%
C09	CC-DSLEASED	Leased Property	100.00%	100.00%	100.00%	100.00%	100.00%
C11	CC-DSMETERS	Meters	98.56%	98.80%	98.89%	98.87%	98.87%
C12	CC-OMACCOUNT	Customer Accounts	98.48%	99.34%	99.14%	99.18%	99.18%
C13	CC-OMSALES	Sales	94.55%	100.00%	100.00%	100.00%	100.00%
C14	CC-OMSERVICE	Customer Service	81.73%	98.86%	99.16%	98.96%	98.96%
C15	CC-OMCC	Customer Accounts Credit Card Fees	100.00%	n/a	n/a	100.00%	100.00%

Calculation of Production Demand and Transmission Cost Indices

Methodology	Total Minnesota Jurisdiction	Residential	General Service	Large Light and Power	Large Power	Lighting
	Revenue Requirements: Production Demand					
P&A	$ 299,961,682	$ 43,857,123	$ 28,535,273	$ 50,793,059	$ 176,100,713	$ 675,514
4CP A&E	$ 299,961,863	$ 54,665,868	$ 31,708,280	$ 54,815,606	$ 158,137,538	$ 634,571
CP Peak Demand (kW)	1,017,672	206,445	103,313	174,270	530,069	3,575
	Production Demand Cost $/kW					
P&A	$ 294.75	$ 212.44	$ 276.20	$ 291.46	$ 332.22	$ 188.95
4CP A&E	$ 294.75	$ 264.80	$ 306.91	$ 314.54	$ 298.33	$ 177.50
	Production Demand Cost Index					
P&A	100	72	94	99	113	64
4CP A&E	100	90	104	107	101	60
	Revenue Requirements: Transmission					
P&A	$ 71,699,449	$ 10,483,263	$ 6,820,532	$ 12,141,195	$ 42,092,882	$ 161,577
12CP	$ 71,699,402	$ 11,158,061	$ 7,308,904	$ 13,078,558	$ 40,062,327	$ 91,552
	Transmission Cost $/kW					
P&A	$ 70.45	$ 50.78	$ 66.02	$ 69.67	$ 79.41	$ 45.20
12CP	$ 70.45	$ 54.05	$ 70.75	$ 75.05	$ 75.58	$ 25.61
	Transmission Cost Index					
P&A	100	72	94	99	113	64
12CP	100	77	100	107	107	36