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-19-442

Exhibit ________

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

November 1, 2019

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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 Supervisor, Revenue Requirements.

Q. Please summarize your qualifications and experience.

A. I have over 13 years of experience with Minnesota Power within the Rates Department. My responsibilities include supporting retail and wholesale general rate cases and other financial regulatory filings, including cost recovery riders. I am responsible for maintaining Minnesota Power's class-cost-of-service model and for 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 2020 Class Cost of Service Study ("CCOSS") and discuss Minnesota Power's evaluation, selection, and implementation of UIPlanner ("UIP") 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 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 (the "Department" or "DOC") 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 2020 CCOSS using the same methodologies as used in the last rate case. I also briefly discuss alternative methodologies Minnesota Power is will be including in this case. I also address an alternative methodology requested by the Department.

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.

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 (the "Commission") Order in the Company's 2016 Rate Case[1] 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) that in future rate case filings,

[1] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 113 (March 12, 2018) ("2016 Rate Case Order").

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.

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 (the "OAG"), and other interested parties to improve the transparency of the Company's future CCOSS. Order Point 55 required the Company to first file a status report identifying the Company's efforts up to that date to facilitate review of its CCOSS model or adopt a new model. 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, 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. 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 had made the decision to acquire and implement UIPlanner.

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. 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 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 first version of the EWM taking into consideration input from stakeholders on suggestions for improvements to transparency and usability of the CCOSS model.

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 approximate impact of the changes on total revenue requirements and other results. This is a major improvement over our past 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.

However, the EWM is not completely dynamic. Any changes other parties would like to make to the external allocation factors, for example, would need to be made by Minnesota Power in the software platform. This also applies to internal allocation factors that would change with any modification to any Total Company input. Although this is a limit to the functionality of the EWM, it will prevent multiple models or versions from being generated by stakeholders and eliminate the potential burden that all parties would need to understand, verify, and confirm each version.

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 and 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; 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 or transparent 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 alternative.

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 reached out to other utilities at an Electric Edison Institute 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 estimated project cost is expected to close out at approximately $1.8 million Total Company. The reduction in cost is being reflected as an adjustment to 2020 average plant in-service, average accumulated amortization, average accumulated deferred income tax, and amortization expense. The details on this adjustment are provided in the Direct Testimony of Company witness Ms. Marcia A. Podratz.

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 first version of EWM is a major improvement over the previous model. In addition, Minnesota Power has also included more detailed schedules on the jurisdictional allocators, bases, and factors in

Volume 3, Schedules B-15 to B-18 and Schedule C-13. The names and codes of some 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 jurisdiction and class based on the adjusted net taxable income by class as determined by the CCOSS, in compliance with Commission requirements.

III. CCOSS MODEL AND RESULTS

A. <u>CCOSS Results</u>

Q. Please provide an overview of the final allocation of revenue requirement to customer class for 2020 test year general rates based on the CCOSS.

A. The results of the CCOSS are summarized in Table 1, below, and also found in Volume 3, Schedule E-3.

Table 1. 2020 Test Year Peak and Average CCOSS Required Revenue Increase by Customer Class

Customer Class	Increase/ (Decrease) to Revenues Required	% Increase/ (Decrease)
Residential	$36,723,375	35.18%
General Service	($69,964)	(-0.10%)
Large Light & Power	$4,834,140	4.44%
Large Power	$23,820,990	7.18%
Lighting	$591,596	16.75%
Total Retail	**$65,900,137**	**10.59%**

Q. Can you provide some context for these results?

A. Yes. The higher required 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. As a result of this history plus the current revenue deficiency, the Residential class is now even further away from its cost of service.

In addition, the relatively high required 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 directly assigned to the Lighting class increased. The Lighting class also received an increased cost allocation for meters, and more customer-related costs have been allocated as a result of increased labor hours being devoted to this class.

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

A. The results show 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.

As discussed in more detail by Company witness Ms. Podratz, Minnesota Power considers the resulting class cost revenue requirements by the three classification components (demand, energy, and customer) to be the appropriate starting points for rate design. The revenue requirements by classification 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 overall cost for each class.

Q. In your opinion, does Minnesota Power's CCOSS provide a reasonable basis for establishing rates in this case?

A. Yes. Minnesota Power's Peak and Average CCOSS provides reasonable 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. Podratz.

Q. Did Minnesota Power generate and include other CCOSS results based on the Peak & Average methodology apart from the 2020 test year General Rates shown above?

A. Yes, a number of other CCOSS results were generated, including 2018 Actual CCOSS, 2019 Projected Year CCOSS, 2020 Unadjusted CCOSS, and 2020 Interim Rate CCOSS. These are included in Volume 4, Workpapers and Other Studies, COS-1 to COS-4. The different adjustments incorporated into the General Rate CCOSS and the Interim Rate CCOSS are discussed by witness Ms. Podratz.

B. Cost Allocation Methods and Testing of Other Methods

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

A. Yes, apart from the 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 made some changes to how some of the external allocators are numbered. In addition, Minnesota Power also renamed many of the external and internal 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.

Q. Is Minnesota Power planning to develop alternative cost allocation methodologies in the CCOSS and submit them as part of this rate case?

A. Yes. Earlier this year, the Department requested that Minnesota Power modify the Peak & Average methodology and submit the results of this modification, named the "DOC Peak & Energy methodology," with our initial rate case filing or shortly thereafter. Given the time required to prepare and validate this alternative methodology, Minnesota Power plans to submit the DOC Peak & Energy methodology in the middle of January 2020 with the results of the requested modification.

Q. Could you briefly describe Minnesota Power's Peak & Average methodology?

A. Yes. The Peak & Average methodology has been used by Minnesota Power in our last three rate cases, and in the current CCOSS, to allocate fixed production and transmission costs to customer class based on a composite allocation factor that is composed of two parts, as shown below:

Composite Allocation Factor = System Load Factor (LF) x (Average Demand Factor)

+

(100 – LF) x (CP Demand Factor)

Q. How would the DOC Peak & Energy method differ from the Company's Peak & Average methodology?

A. Rather than allocating all fixed production as 100 percent demand, the Department requested that we use the system load factor (approximately 86 percent) to classify that portion of fixed production costs as energy-related and allocate separately on average demand (or energy), then classify the remaining portion (1 – LF) (approximately 14 percent) as demand-related and allocate based on one coincident peak ("1CP") based on Minnesota Power's system peak. The Department has also requested that Transmission costs be allocated on 1CP.

C. Other Refinements to the CCOSS

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 moved those customers to either the General Service class or Large Light and Power class. Therefore, the Municipal Pumping class is no longer in the CCOSS for 2019 and 2020.

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

A. In the process of implementing UIPlanner a number of 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, an additional reporting line has been added for Solar, 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 last 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 2020 test year budget as continuing rider adjustments, which is more readily accomplished in the new model.

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 (Docket #ER11-134-000). The contra AFUDC lines were added prior to our last rate case to Plant, 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 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 O&M expense, interest on customer deposits, labor only ratio for O&M expense fuel, allocating transmission payroll taxes, internal allocators for contra AFUDC, and mapping of AFUDC.

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. 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 O&M Expense?

A. Previously, Transmission O&M Expense was allocated based on the external DTRAN Transmission allocator. It is now more accurately allocated using an internal allocator (OMTRAN), 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 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 allocating Payroll Taxes - Transmission?

A. Payroll Taxes – Transmission were previously allocated based on transmission O&M expense. Consistent with the use of internal labor-related allocators for other payroll taxes, Payroll Taxes – Transmission are now allocated on an internal labor allocator (OMLTRAN).

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

A. 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 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, jurisdiction, and customer class based on allocation factors.

Production

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

Transmission

5. Transmission Production
6. Transmission

Distribution

7. Distribution - Primary Overhead Lines
8. Distribution - Primary Underground Lines
9. Distribution - Secondary Overhead Lines
10. Distribution - Secondary Underground Lines
11. Distribution - Secondary Overhead Transformers
12. Distribution - Secondary Underground Transformer
13. Distribution - Secondary Overhead Services
14. Distribution - Secondary Underground Services
15. Distribution - Secondary Leased Property
16. Distribution - Secondary Street Lighting
17. Distribution - Other Meters
18. Distribution – Other Distribution Production
19. Distribution - Other Distribution Bulk Delivery

20. Distribution – Other Distribution Bulk Delivery Specific Assignment

21. Distribution – Other Distribution Primary Specific Assignment

General Plant

Intangible Plant

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, 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, 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 energy 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 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 2, and the Distribution Plant Study is included in Volume 4, Workpapers and Other Studies, OS-1.

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			

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. Table 5 shows the related classification allocator bases and Table 6 shows the classification allocation factors.

Q. Were the classification methodologies developed using the same methodologies as in Minnesota Power's last 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 last 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 last 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 jurisdiction and customer class, 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 last 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, 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 loads in each jurisdiction at the time of Minnesota Power's twelve 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 (kWh), excluding Large Power Replacement Firm Power Service ("RFPS") energy and Fixed-Price Silver Bay Power 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 last 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 (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 2018, 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 and test year use the same actual allocation ratios as 2018?

A. No. To develop the projected year, the Company allocated the actual number of hours worked from January to June 2019 and projected hours for the remaining months in

2019. These numbers of hours were then allocated according to time spent among the two jurisdictions and by rate classes. The ratios developed for 2019 were then applied to the dollars amounts. The 2020 test year budgeted amounts were allocated using the 2019 ratios to determine 2020 allocation factors.

Q. Why did the Company develop new ratios for the projected year and test year?

A. In 2018 and early 2019, the Company went through changes in personnel, including personnel movement from one department to another, and department restructuring. Therefore the ratios used in 2018 were no longer representative for 2019 and 2020.

Nonetheless, the jurisdictional separation of customer costs in the present filing follows the same procedures approved in Minnesota Power's last three retail rate cases (Docket No. E-015/GR-08-415, E-015/GR-09-1151, 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 retail filing?

A. The comparison of the jurisdictional allocation factors is shown in MP Exhibit ___ (Shimmin), Direct Schedule 2 attached to my testimony.

The test year jurisdictional allocation factor ratios used in Minnesota Power's CCOSS can be found in Volume 3, Schedules B-15 to B-18 and Schedule C-13 to C-16. Direct Schedule B-15 lists the rate base components by CCOSS reporting line and provides the jurisdictional allocator names/codes for each customer, demand, and energy classification where appropriate. Direct Schedule B-16 provides the Total Company jurisdictional allocator bases by classification for the Unadjusted Most Recent Fiscal Year 2018, Unadjusted Projected Fiscal Year 2019, and Proposed Test Year 2020. Direct Schedule B-17 provides the Minnesota Jurisdiction allocator bases by classification for the Unadjusted Most Recent Fiscal Year 2018, Unadjusted Projected Fiscal Year 2019, and Proposed Test Year 2020. Direct Schedule B-18 provides the Minnesota Jurisdiction allocator factors by classification for the

Unadjusted Most Recent Fiscal Year 2018, Unadjusted Projected Fiscal Year 2019, and Proposed Test Year 2020. Direct Schedule C-13 lists the Operating Income components by CCOSS reporting line and provides the jurisdictional allocator names/codes for each customer, demand, and energy classification where appropriate. Direct Schedules C-14, C-15 and C-16 reference back to Direct Schedules B-16, B-17 and B-18 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, a couple of changes in Minnesota Power's operations have impacted the jurisdictional allocations since our last case. The trend seen in demand and energy allocators D-01, D-02, D-03, and E-01 from the 2017 test year through the 2020 test year reflects a combination of two major events that decreased Minnesota Power's non-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, and 2) in mid-2019 Minnesota Power lost Brainerd as a firm Municipal customer. The trend seen in the customer allocators C-13 and C-14 from the 2017 test year to the 2020 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 Other 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.

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 2018, 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 Other Studies, AF-1.

(b) Energy allocation factors analyses—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 2018, 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. In developing the E8760 energy allocator, 2013 to 2014 load research results on the annual hourly load shapes were used in scaling 2020 test year budgeted energy. Refer to Exhibit ___ (Shimmin), Direct Schedule 1, Guide to Minnesota Power's CCOSS, and to Volume 4, Workpapers and Other Studies, AF-1.[2]

(c) Customer allocation factors analyses—Analyses of the number of customers using facilities, plant balances by class, and labor expenses and hours were carried out in developing the customer allocation factors. The analyses were based on the most recently available historical data from 2018, actual data through June 2019, projected data from July to December 2019, 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 Other Studies, AF-1.

(d) Distribution Plant Study, including minimum-system—Results from the Distribution Plant Study were utilized to sub-functionalize and classify distribution plant into both demand- and customer-related components. The Distribution Plant Study was updated since Minnesota Power's last rate case and is based on analyses of 2018 data and field conditions. The report is included in Volume 4, Workpapers and Other Studies, OS-1.

(e) Lead-Lag Study—Revenue lead days and expense lag days from the 2017 Lead-Lag Study were utilized in estimating test year cash working capital. The Lead-Lag

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

Study was developed based on 2017 data. The report is included in Volume 4, Workpapers and Other Studies, OS-2.

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

A. The Company is using customary practices to allocate costs among customer classes, which result in reasonable overall costs allocations. As discussed above, the final required 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 "In future rate cases, cost recovery for facilities shall be rolled in at the beginning of the rate case, and then no longer be recovered in riders, or facilities and rider collections shall be rolled into the rate case at the end of the rate case if Minnesota Power wants to continue rider recovery."

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, Minnesota Power is moving costs for capital projects completed before the test year into base rates at the beginning of this rate case.

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");
- Boswell Energy Center Unit 4 ("BEC4") Emission Reduction Rider ("BEC4 Rider");
- Fuel and Purchased Energy Rider (discussed by Company witness Ms. Podratz); and
- Conservation Program Adjustment (discussed by Company witness Ms. Podratz).

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

A. Yes. Table 3 below summarizes the projects and costs that will remain in each of the riders discussed in my testimony and the projects and costs that will be incorporated into base rates. These are discussed in more detail below, including the Solar Factor that is not yet in a rider.

Table 3. Summary of Rider Treatment in 2020 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 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
Boswell Energy Center Unit 4 Emission Reduction Rider	
Moving to Base Rates	**Staying in the Rider**
	Basin Credit (end April 2020)
Solar Factor (under RRR)	
Moving to Base Rates	**Staying in the Rider**
	Camp Ripley
	Solar Garden

Q. What revenues and expenses does Minnesota Power propose to continue to include in the TCR Rider?

A. As stated in Minnesota Power’s 2019 Transmission Cost Recovery Rider Petition submitted on July 9, 2019 (Docket No. E015/M-19-440), Minnesota Power proposes to continue to use the TCR Rider to recover costs for two items: (1) the Great Northern Transmission Line Project (“GNTL”) (Docket Nos. E015/CN-12-1163 and E015/TL-14-21*)*; and (2) 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 because GNTL will not be completed and in-service before the start of the test year.

GNTL is expected to be in-service at the end of June 2020. Because Minnesota Power utilizes an average method to calculate rate base cost in the test year, if the costs were rolled into base rates, the Company would not recover the full amount of the in-service costs.

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 as a MISO member. Minnesota Power will continue providing a credit in the TCR Rider for the MVP revenues it receives. As required by the May 11, 2011 Commission Order in Minnesota Power's 2010 TCR Rider Docket (Docket No. E015/M-10-799), internal capitalized labor costs will continue to be excluded from recovery in the TCR, RRR, and BEC4 Riders. This is discussed in more detail below.

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, 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. Dan W. 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. As stated in Minnesota Power's 2020 Renewable Resources Rider Petition submitted to the Commission for approval on August 15, 2019 (Docket No. E015/M-19-523), Minnesota Power proposes continued use of the RRR for two items. 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. Additionally, revenues received from the sale of Renewable Energy Credits ("RECs") to Oconto Electric Cooperative, and any other future sale of RECs, would be shared with customers through the RRR.

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. 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 Mr. Joshua J. Skelton discusses these costs and why it is appropriate for the Company to recover its investments in the two remaining projects to restore of the Thomson Hydroelectric facility.

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

A. As discussed in Minnesota Power's most recent RRR filing (Docket No. E015/M-19-523), Minnesota Power is also 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 ALLETE Clean Energy ("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 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 2020 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. To effectuate this, Minnesota Power has set up a negative plant balance that is included in both the beginning and ending plant balances for the 2020 test year. This will ensure 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 inadvertently left the payment from ACE to Minnesota Power out of its initial 2020 budget, so an adjustment to reflect the additional revenue is being made as discussed by Company witness Ms. Podratz.

Q. What does Minnesota Power propose with respect to the BEC4 Rider?

A. Minnesota Power proposes to end the BEC4 Rider as the tracker balance reaches zero for each of the Large Power and All Other Classes. The Boswell Ash Management project that was the last project in the BEC4 Rider has been indefinitely delayed; therefore, the costs related to the Boswell Ash Management project were removed from the BEC4 Rider effective April, 2019. The power sale to Basin Electric Power Cooperative ("Basin") will terminate on April 30, 2020; accordingly, the revenue credit to customers associated with Basin's share of the BEC4 Mercury Emission Reduction project costs will also terminate on that date. As such, no additional revenue requirements will be added to the BEC4 Rider after April of 2020. Minnesota Power would like to continue to keep the current factors (credits to customers) in place until each group's tracker responsibility is near zero. Current projections of the remaining revenue requirements and billing units result in a projected date of July 1, 2020 for a near-zero tracker balance for the "All Other Classes" group, and a projected date of May 1, 2021 for a near-zero tracker balance for the Large Power customer class. When each tracker balance approaches zero, Minnesota Power proposes to zero out the factors and make a one-time charge or credit on customer bills to completely zero out the tracker balance. After both tracker balances are zero, Minnesota Power will then submit a compliance filing to terminate the BEC4 Rider.

Q. Are there any cost recovery rider factors that Minnesota Power plans to establish in the near future?

A. Minnesota Power plans to file a Solar Renewable Factor, as authorized under the Renewable Resources Rider, to recover the costs of meeting Minnesota's Solar Energy Standard ("SES").

Q. How are costs related to Minnesota Power's solar projects being treated?

A. The costs related to Minnesota Power's Camp Ripley Solar project and the Community Solar Garden projects are not included in Minnesota Power's recent RRR filing (Docket No. E015/M-19-523). These costs are accumulating in a tracker account and will be included in the Solar Renewable Factor in the future. The Commission approved a new Solar Renewable Factor as part of the Camp Ripley Solar Project filing in Docket E015/M-15-773, to appropriately allocate costs to customers as set out in SES. The SES includes a provision that exempts certain customers from paying costs to meet the SES. Because of this, all solar-related costs are excluded from the 2020 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 be excluded from future rate cases, and included on bills of non-exempt customers as the "Solar factor."

Q. Has the 2020 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 2020 test year. These adjustments are discussed by witness Ms. Podratz and are shown in Volume 3, Schedule B-5 and Schedule C-9. Details are also shown in Volume 4, Workpapers and Other Studies, ADJ-RB-9.

Q. Are internal capitalized labor costs associated with rider projects recovered in these riders?

A. No. In Minnesota Power's 2010 TCR Rider proceedings, (Docket No. E015/M-10-799), the Commission determined that internal labor costs capitalized in assets should be excluded when determining the revenue requirements for current cost recovery riders. Rather, the Commission determined that Minnesota Power could seek a return on, and recovery of, the remaining undepreciated balance in the utility's next rate proceeding. Since the issuance of the Commission's Order in that docket, all internalized costs have been backed out or reduced from the total asset costs in calculating revenue requirements for riders.

Q. How are internal capitalized labor costs for rider projects included in Minnesota Power's current rate case?

A. The total 2020 test year labor costs are budgeted in two areas: A portion is budgeted in labor as an expense and a portion is budgeted in project costs as a capitalized cost. Minnesota Power is excluding all capital project costs related to projects staying in the rider as discussed above, effectively excluding the labor costs capitalized in those projects. Since these project costs cannot be recovered (as discussed above by Commission Order), they must be added back to O&M as an adjustment to the 2020 test year. This is consistent with how capitalized internal labor for continuing rider projects was handled in Minnesota Power's 2016 Rate Case. This adjustment to O&M is discussed by Company witness Ms. Podratz and is shown in Volume 3, Schedule C-9 and in Volume 4, Workpaper and Other Studies, ADJ-IS-29.

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

Table of Contents

<u>Tables</u>

Description of Externally Developed Allocation Factors

I. INTRODUCTION

This guide discusses the functionalization, classification, and allocation methodologies used in the CCOSS process. It includes:

- 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 or number of the allocator. Table 5 provides the classification allocator bases and Table 6 shows the classification allocator factors.

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

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

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

The externally-developed allocation factors listed in the Table of Contents are described below and are detailed in Volume 4, Workpapers, under Allocation Factors. There are three types of external allocation factors: demand, energy, and customer. The allocator number is preceded by a letter prefix to indicate the type: D-XX for demand, E-XX for energy, C-XX for customer. For example: D-01, E-01, and C-01.

For coding in UIPlanner ("UIP"), each of the allocators were given another prefix depending on how the allocator is used. If the allocator is used for the jurisdictional split between Minnesota and FERC jurisdictions, it is preceded by the letter "J". For example: J-D-01, J-E-01, and J-C-01. If the allocator is used for allocating to customer class, it is preceded by the letters "CC". For example: CC-D-01, CC-E-01, and CC-C-01.

The jurisdictional allocator bases and factors for rate base line items are shown in Volume 3, Direct Schedule B-15 to B-18. The jurisdictional allocator bases and factors for income statement line items are shown in Volume 3, Direct Schedules C-13 to C-16.

B. Internal Allocation Factors

Internally-developed jurisdictional and customer class 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, jurisdictional bases, and jurisdictional allocators as also shown in in Volume 3, Direct Schedules B-15 to B-18 and C-13 to C-16.

Apart from the classification ratios developed in the Distribution Plant Study described below to classify distribution plant, the other classification allocation factors are internally-developed within the CCOSS. The classification allocator names are preceded by the letter "C". For example, C-Steam. The classification allocator names are shown in Table 4. The classification allocator bases are shown in Table 5 and the classification allocator factors are shown in Table 6.

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-6, 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 E015/GR-08-415, Docket 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 jurisdictions 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 very 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 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." see 7/11/80 Testimony of Phillip Zins, Docket No. E015/GR-80-76, at 29. In addition, the methodology results in allocation factors that are very similar to those developed using MP's historic methodology, the CAPSUBPOD method. Based on these considerations, MP 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 composite energy/demand allocator. NARUC (Chapter 4) characterizes these methods as "partial energy weighing methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy load but do not take the second step of classifying the costs as energy-related."

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:

Composite Allocation Factor = LF x (Average Demand Factor)
\+
(100 – LF) x (CP Demand Factor)

The development of the Production – Demand jurisdictional and class allocators (D-01) are detailed in Volume 4, Workpapers, under Allocation Factors.

C. Hydro Plant: FERC accounts 330-336

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

This method is consistent with Minnesota Power's last 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).

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

Hydro Production – Energy is allocated between Minnesota Power's FERC and MPUC jurisdictions based on energy. The energy responsibility factors (E-01) 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.

Hydro Production - Energy is allocated among Minnesota Power's retail customer classes using the 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 jurisdictional and class allocators (E-01 and 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 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.

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 jurisdiction and 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 (D-02) 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	372	373
D100 Dist - Substations 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		
D675 Dist - Leased Property											X	
D700 Dist - Street Lighting												X

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

Substations

D100 Distribution – Substations Non Bulk Delivery is classified as demand.
D123 Distribution – Substations 23kv Bulk Delivery is classified as demand.
D134 Distribution – Substations 34kv Bulk Delivery is classified as demand.
D146 Distribution – Substations 46kv 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 23kv is classified as demand.
D234 Distribution – Bulk Delivery Lines 34kv is classified as demand.
D246 Distribution – Bulk Delivery Lines 46kv 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.

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.

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

Function / Subfunction		Jurisdictional Allocation	Retail Class Allocation: Demand	Retail Class Allocation: Customer
		Basis of Jurisdictional Cost Allocation by Classification		
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
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 (C-11).

Leased Property (C-9) and Street Lighting (C-10) 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 (D-01).

Distribution Bulk Delivery plant are 23kV, 34kVand 46kV facilities that serve both FERC and retail jurisdictional customers. These facilities, sometimes referred to a subtransmission, 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 (D-03).

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 14kV and 23kV, 34kV and 46kV 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 (D-03 thru D-15) or customer allocation factors (C-01 thru C-11).

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 (C-01, C-02), secondary lines (C-03, C-04), transformers (C-05, C-06) 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 (C-11).

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 (D-03), Distribution Substations (D-05/09) and Primary Line Facilities (D-06, D-07) 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 (D-12, D-13) 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 (D-10, D-11) and Services level (D-14, D-15) 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 390-398

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 301-303.1

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 E-01 and to class using allocator E8760. This treatment is the same as Fuel Expense (a/c 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 subfunctionalized to production, transmission, and distribution on most recent calendar year FERC Form 1 amounts. Distribution is then subfunctionalized/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 (a/c 165.1, 165.8) 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 (a/c 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 (a/c 18640.6023) is classified to energy and is allocated to jurisdiction using energy allocator E-01 and to class using allocator 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 MPUC Order.

O. 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).

P. 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 (D-02).

Q. 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 (D-02).

R. 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% of the value of the customer advances and deposits.

S. 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.

T. 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.

U. 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 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 (D-01), and sales classified as energy are allocated to class using allocator 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 jurisdiction on energy (E-01) and to class using allocator 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 (D-01).

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 (D-01).

Sales classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760 allocator. All intersystem sales revenues are treated as revenue credits and are allocated back to Minnesota Power's FERC and retail jurisdictional customers.

G. <u>Other Operating Revenue: FERC accounts 450, 454, 456</u>

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 subfunctionalized 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 6 attached to the Direct Testimony of witness Ms. Marcia Podratz for a descriptive list of Other Operating Revenue.

H. <u>Operation & Maintenance Expense – Steam Production: FERC accounts 500-503, 505-506, 510-514</u>

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 (D-01).

Expenses classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760 allocation.

I. <u>Operation & Maintenance Expense – Hydro Production: FERC accounts 535, 537-539, 541-545</u>

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 (D-01).

Expenses classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760 allocator.

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 (D-01).

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 D-02 Transmission allocator. With the implementation of the UIP, these expenses are now more accurately allocated on a new internal allocator (OMTRAN) that follows the three components of transmission plant: production, transmission and ADFUDC 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 (C-11) 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 (D-01).

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 (D-01).

Expenses classified as energy are allocated to jurisdiction on energy (E-01) and to class on the E8760 allocation.

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 jurisdiction on energy (E-01) and to class on the E8760 allocation.

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 (C-12). 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 (C-15).

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 (C-17). 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 CCRC 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 (C-13). 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 (D-02).

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. 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.

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

EE. 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.

FF. 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.

GG. 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.

HH. ARO Accretion Expense: FERC account 411.1

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

II. 2020 Rate Case 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.

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 jurisdiction on energy (E-01) and to class on the E8760 allocator. 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. <u>Federal Current Income Tax</u>

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. <u>Provision for Deferred Income Tax: FERC accounts 410.1, 411.1</u>

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. <u>Investment Tax Credit: FERC account 411.4</u>

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

Allowance for Funds Used During Construction ("AFUDC") are functionalized, classified, and allocated to jurisdiction and class following the treatment of the corresponding CWIP.

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

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 / Number of Allocator	Name / Number of Jurisdictional Allocator 12/	Name / Number of Customer Class Allocator
	RATE BASE												
1	**PLANT IN SERVICE**												
2	STEAM												
3	PRODUCTION - DEMAND	310-317		C-STEAM	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
4	STEAM CONTRA			C-STEAM	X	-	-	Direct	-	(I)	Contra-01	J-Contra-01	CC-D-01
5	HYDRO												
6	PRODUCTION - DEMAND	330-336		C-HYDRO	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
7	PRODUCTION - ENERGY	B200	2/	C-HYDRO	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
8	HYDRO CONTRA - DEMAND			C-HYDRO	X	-	-	Direct	-	(I)	Contra-02	J-Contra-02	CC-D-01
9	HYDRO CONTRA - ENERGY			C-HYDRO	-	X	-	Direct	-	(I)	Contra-02	J-Contra-02	CC-E-01
10	WIND												
11	PRODUCTION - DEMAND	340-347 (ex. Solar)		C-WIND	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
12	WIND CONTRA			C-WIND	X	-	-	Direct	-	(I)	Contra-03	J-Contra-03	CC-D-01
13	SOLAR												
14	PRODUCTION - DEMAND	340.1/.6, 341.5, 342.5, 343.5, 344.5, 346.5, 347.5, 355.5		C-SOLAR	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
15	TRANSMISSION												
16	TRANSMISSION PRODUCTION	C200	3/	C-TRAN	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
17	TRANSMISSION	352-359.9		C-TRAN	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
18	TRANMISSION CONTRA			C-TRAN	X	-	-	Direct	-	(I)	Contra-05	J-Contra-05	CC-D-02
19	DISTRIBUTION	360-373	4/										
20	PRIMARY												
21	OVERHEAD LINES - DEMAND	D300		C-DPOHL	X	-	-	-	Class NCP	(E)	D-06	J-D-06	CC-D-06
22	OVERHEAD LINES - CUSTOMER	D300		C-DPOHL	-	-	X	-	Customers	(E)	C-01	J-C-01	CC-C-01
23	UNGRD LINES - DEMAND	D400		C-DPUGL	X	-	-	-	Class NCP	(E)	D-07	J-D-07	CC-D-07
24	UNGRD LINES - CUSTOMER	D400		C-DPUGL	-	-	X	-	Customers	(E)	C-02	J-C-02	CC-C-02
25	SECONDARY												
26	OVHD LINES - DEMAND	D300		C-DSOHL	X	-	-	-	Sum NCP	(E)	D-10	J-D-10	CC-D-10
27	OVHD LINES - CUSTOMER	D300		C-DSOHL	-	-	X	-	Customers	(E)	C-03	J-C-03	CC-C-03
28	UNGRD LINES - DEMAND	D400		C-DSUGL	X	-	-	-	Sum NCP	(E)	D-11	J-D-11	CC-D-11
29	UNGRD LINES - CUSTOMER	D400		C-DSUGL	-	-	X	-	Customers	(E)	C-04	J-C-04	CC-C-04
30	OVHD LINE TRANSFRM - DEMAND	D500		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	D-12	J-D-12	CC-D-12
31	OVHD LINE TRANSFRMS - CUSTOMER	D500		C-DSOHT	-	-	X	-	Customers	(E)	C-05	J-C-05	CC-C-05
32	UNGRD LINE TRANSFRMS - DEMAND	D500		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	D-13	J-D-13	CC-D-13
33	UNGRD LINE TRANSFRMS - CUSTOMER	D500		C-DSUGT	-	-	X	-	Customers	(E)	C-06	J-C-06	CC-C-06
34	OVHD SERVICES - DEMAND	369		C-DSOHS	X	-	-	-	Sum NCP	(E)	D-14	J-D-14	CC-D-14
35	OVERHEAD SERVICES - CUSTOMER	369		C-DSOHS	-	-	X	-	Customers	(E)	C-07	J-C-07	CC-C-07
36	UNGRD SERVICES - DEMAND	369		C-DSUGS	X	-	-	-	Sum NCP	(E)	D-15	J-D-15	CC-D-15
37	UNGRD SERVICES - CUSTOMER	369		C-DSUGS	-	-	X	-	Customers	(E)	C-08	J-C-08	CC-C-08
38	LEASED PROPERTY	372		C-DSLEASED	-	-	X	-	Direct	(E)	C-09	J-C-09	CC-C-09
39	STREET LIGHTING	373		D-DSLIGHTING	-	-	X	-	Direct	(E)	C-10	J-C-10	CC-C-10
40	DISTRIBUTION OTHER												
41	METERS	370		C-DSMETERS	-	-	X	Meter counts & cost		(E)	C-11	J-C-11	CC-C-11
42	PRODUCTION - DEMAND	D200	5/	C-DOPROD	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
43	DISTRIBUTION BULK DELIVERY		6/	C-DODBD	X	-	-	NCP	Class NCP	(E)	D-03	J-D-03	CC-D-03
44	DISTRIBUTION SUBSTATIONS	D100		C-DODSUB	X	-	-	-	Class NCP	(E)	D-05	J-D-05	CC-D-05
45	DIST BULK DEL SPECIFIC ASSIGN		7/	D-DODBDSA	X	-	-	Direct	-	(E)	D-04	J-D-04	CC-D-04
46	DIST PRIMARY SPECIFIC ASSIGN	D100		D-DODPSA	X	-	-	Direct	-	(E)	D-08	J-D-08	CC-D-08
47	DISTRIBUTION CONTRA			C-DXCONTRA	X	-	X	Direct	-	(I)	DXCONTRA	J-DXCONTRA	CC-DXCONTRA
48	GENERAL PLANT												
49	GENERAL PLANT	390-398		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
50	GENERAL PLANT CONTRA	390-399		C-OMLXAG	X	-	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
51	INTANGIBLE PLANT												
52	INTANGILBE PLANT	301-303.1		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
53	**CONSTRUCTION WORK IN PROGRESS**												
54	STEAM												
55	PRODUCTION - DEMAND	107		C-STEAMCWIP	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
56	STEAM CONTRA			C-STEAMCWIP	X	-	-	Direct	-	(I)	Contra-06	J-Contra-06	CC-D-01
57	HYDRO												
58	PRODUCTION - DEMAND	107		C-HYDROCWIP	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
59	PRODUCTION - ENERGY	107		C-HYDROCWIP	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
60	HYDRO CONTRA - DEMAND			C-HYDROCWIP	X	-	-	Direct	-	(I)	Contra-07	J-Contra-07	CC-D-01

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

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61	HYDRO CONTRA - ENERGY			C-HYDROCWIP	-	X	-	Direct	-	(I)	Contra-07	J-Contra-07	CC-E-01
62	WIND												
63	PRODUCTION - DEMAND	107		C-WINDCWIP	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
64	WIND CONTRA			C-WINDCWIP	X	-	-	Direct	-	(I)	Contra-08	J-Contra-08	CC-D-01
65	SOLAR												
66	PRODUCTION - DEMAND	107		C-SOLARCWIP	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
67	SOLAR CONTRA			C-SOLARCWIP	X	-	-	Direct	-	(I)	Contra-09	J-Contra-09	CC-D-01
68	TRANSMISSION												
69	TRANSMISSION PRODUCTION	107		C-TRANCWIP	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-02
70	TRANSMISSION	107		C-TRANCWIP	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
71	TRANMISSION CONTRA			C-TRANCWIP	X	-	-	Direct	-	(I)	Contra-10	J-Contra-10	CC-D-02
72	DISTRIBUTION	107											
73	PRIMARY												
74	OVERHEAD LINES - DEMAND	D300		C-DPOHL	X	-	-	-	Class NCP	(E)	D-06	J-D-06	CC-D-06
75	OVERHEAD LINES - CUSTOMER	D300		C-DPOHL	-	-	X	-	Customers	(E)	C-01	J-C-01	CC-C-01
76	UNGRD LINES - DEMAND	D400		C-DPUGL	X	-	-	-	Class NCP	(E)	D-07	J-D-07	CC-D-07
77	UNGRD LINES - CUSTOMER	D400		C-DPUGL	-	-	X	-	Customers	(E)	C-02	J-C-02	CC-C-02
78	SECONDARY												
79	OVHD LINES - DEMAND	107		C-DSOHL	X	-	-	-	Sum NCP	(E)	D-10	J-D-10	CC-D-10
80	OVHD LINES - CUSTOMER	107		C-DSOHL	-	-	X	-	Customers	(E)	C-03	J-C-03	CC-C-03
81	UNGRD LINES - DEMAND	107		C-DSUGL	X	-	-	-	Sum NCP	(E)	D-11	J-D-11	CC-D-11
82	UNGRD LINES - CUSTOMER	107		C-DSUGL	-	-	X	-	Customers	(E)	C-04	J-C-04	CC-C-04
83	OVHD LINE TRANSFRM - DEMAND	107		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	D-12	J-D-12	CC-D-12
84	OVHD LINE TRANSFRMS - CUSTOMER	107		C-DSOHT	-	-	X	-	Customers	(E)	C-05	J-C-05	CC-C-05
85	UNGRD LINE TRANSFRMS - DEMAND	107		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	D-13	J-D-13	CC-D-13
86	UNGRD LINE TRANSFRMS - CUSTOMER	107		C-DSUGT	-	-	X	-	Customers	(E)	C-06	J-C-06	CC-C-06
87	OVHD SERVICES - DEMAND	369		C-DSOHS	X	-	-	-	Sum NCP	(E)	D-14	J-D-14	CC-D-14
88	OVERHEAD SERVICES - CUSTOMER	369		C-DSOHS	-	-	X	-	Customers	(E)	C-07	J-C-07	CC-C-07
89	UNGRD SERVICES - DEMAND	369		C-DSUGS	X	-	-	-	Sum NCP	(E)	D-15	J-D-15	CC-D-15
90	UNGRD SERVICES - CUSTOMER	369		C-DSUGS	-	-	X	-	Customers	(E)	C-08	J-C-08	CC-C-08
91	LEASED PROPERTY	372		C-DSLEASED	-	-	X	-	Direct	(E)	C-09	J-C-09	CC-C-09
92	STREET LIGHTING	373		C-DSLIGHTING	-	-	X	-	Direct	(E)	C-10	J-C-10	CC-C-10
93	DISTRIBUTION OTHER												
94	METERS	107		C-DSMETERS	-	-	X	Meter counts & cost		(E)	C-11	J-C-11	CC-C-11
95	PRODUCTION - DEMAND	107		C-DOPROD	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
96	DISTRIBUTION BULK DELIVERY			C-DODBD	X	-	-	NCP	Class NCP	(E)	D-03	J-D-03	CC-D-03
97	DISTRIBUTION SUBSTATIONS	107		C-DODSUB	X	-	-	-	Class NCP	(E)	D-05	J-D-05	CC-D-05
98	DIST BULK DEL SPECIFIC ASSIGN			C-DODBDSA	X	-	-	Direct	-	(E)	D-04	J-D-04	CC-D-04
99	DIST PRIMARY SPECIFIC ASSIGN	107		C-DODPSA	X	-	-	Direct	-	(E)	D-08	J-D-08	CC-D-08
100	GENERAL PLANT												
101	GENERAL PLANT	107		C-GENPLANT	X	X	X	Total O&M Labor less A&G		(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
102	INTANGIBLE PLANT												
103	INTANGILBE PLANT	107		C-INTPLANT	X	X	X	Total O&M Labor less A&G		(I)	INTPLANT	J-INTPLANT	CC-INTPLANT
104	**ACCUMULATED DEPRECIATION**												
105	STEAM												
106	PRODUCTION - DEMAND	108, 110		C-Steam	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
107	STEAM CONTRA			C-Steam	X	-	-	Direct	-	(I)	Contra-11	J-Contra-11	CC-D-01
108	HYDRO												
109	PRODUCTION - DEMAND	108, 110		C-Hydro	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
110	PRODUCTION - ENERGY	108, 110		C-Hydro	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
111	HYDRO CONTRA - DEMAND			C-Hydro	X	-	-	Direct	-	(I)	Contra-12	J-Contra-12	CC-D-01
112	HYDRO CONTRA - ENERGY			C-Hydro	-	X	-	Direct	-	(I)	Contra-12	J-Contra-12	CC-E-01
113	WIND												
114	PRODUCTION - DEMAND	108, 110		C-Wind	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
115	WIND CONTRA			C-Wind	X	-	-	Direct	-	(I)	Contra-13	J-Contra-13	CC-D-01
116	SOLAR												
117	PRODUCTION - DEMAND	108, 110		C-Solar	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
118	TRANSMISSION												
119	TRANSMISSION PRODUCTION	108, 110		C-Tran	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
120	TRANSMISSION	108, 110		C-Tran	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
121	TRANMISSION CONTRA			C-Tran	X	-	-	Direct	-	(I)	Contra-15	J-Contra-15	CC-D-02
122	DISTRIBUTION	108, 110											
123	PRIMARY												

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 / Number of Allocator	Name / Number of Jurisdictional Allocator 12/	Name / Number of Customer Class Allocator
124	OVERHEAD LINES - DEMAND	108, 110		C-DPOHL	X	-	-	-	Class NCP	(E)	D-06	J-D-06	CC-D-06
125	OVERHEAD LINES - CUSTOMER	108, 110		C-DPOHL	-	-	X	-	Customers	(E)	C-01	J-C-01	CC-C-01
126	UNGRD LINES - DEMAND	108, 110		C-DPUGL	X	-	-	-	Class NCP	(E)	D-07	J-D-07	CC-D-07
127	UNGRD LINES - CUSTOMER	108, 110		C-DPUGL	-	-	X	-	Customers	(E)	C-02	J-C-02	CC-C-02
128	SECONDARY												
129	OVHD LINES - DEMAND	108, 110		C-DSOHL	X	-	-	-	Sum NCP	(E)	D-10	J-D-10	CC-D-10
130	OVHD LINES - CUSTOMER	108, 110		C-DSOHL	-	-	X	-	Customers	(E)	C-03	J-C-03	CC-C-03
131	UNGRD LINES - DEMAND	108, 110		C-DSUGL	X	-	-	-	Sum NCP	(E)	D-11	J-D-11	CC-D-11
132	UNGRD LINES - CUSTOMER	108, 110		C-DSUGL	-	-	X	-	Customers	(E)	C-04	J-C-04	CC-C-04
133	OVHD LINE TRANSFRM - DEMAND	108, 110		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	D-12	J-D-12	CC-D-12
134	OVHD LINE TRANSFRMS - CUSTOMER	108, 110		C-DSOHT	-	-	X	-	Customers	(E)	C-05	J-C-05	CC-C-05
135	UNGRD LINE TRANSFRMS - DEMAND	108, 110		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	D-13	J-D-13	CC-D-13
136	UNGRD LINE TRANSFRMS - CUSTOMER	108, 110		C-DSUGT	-	-	X	-	Customers	(E)	C-06	J-C-06	CC-C-06
137	OVHD SERVICES - DEMAND	108, 110		C-DSOHS	X	-	-	-	Sum NCP	(E)	D-14	J-D-14	CC-D-14
138	OVERHEAD SERVICES - CUSTOMER	108, 110		C-DSOHS	-	-	X	-	Customers	(E)	C-07	J-C-07	CC-C-07
139	UNGRD SERVICES - DEMAND	108, 110		C-DSUGS	X	-	-	-	Sum NCP	(E)	D-15	J-D-15	CC-D-15
140	UNGRD SERVICES - CUSTOMER	108, 110		C-DSUGS	-	-	X	-	Customers	(E)	C-08	J-C-08	CC-C-08
141	LEASED PROPERTY	108, 110		C-DSLEASED	-	-	X	-	Direct	(E)	C-14	J-C-14	CC-C-14
142	STREET LIGHTING	108, 110		C-DSLIGHTING	-	-	X	-	Direct	(E)	C-10	J-C-10	CC-C-10
143	DISTRIBUTION OTHER												
144	METERS	108, 110		C-DSMETERS	-	-	X	Meter counts & cost		(E)	C-11	J-C-11	CC-C-11
145	PRODUCTION - DEMAND	108, 110		C-DOPROD	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
146	DISTRIBUTION BULK DELIVERY			C-DODBD	X	-	-	NCP	Class NCP	(E)	D-03	J-D-03	CC-D-03
147	DISTRIBUTION SUBSTATIONS	108, 110		C-DODSUB	X	-	-	-	Class NCP	(E)	D-05	J-D-05	CC-D-05
148	DIST BULK DEL SPECIFIC ASSIGN			C-DODBDSA	X	-	-	Direct	-	(E)	D-04	J-D-04	CC-D-04
149	DIST PRIMARY SPECIFIC ASSIGN	108, 110		C-DODPSA	X	-	-	Direct	-	(E)	D-08	J-D-08	CC-D-08
150	DISTRIBUTION CONTRA			C-ADDXCONTRA	X	-	X	Direct	-	(I)	ADDXCONTRA	J-ADDXCONTRA	CC-ADDXCONTRA
151	GENERAL PLANT												
152	GENERAL PLANT	108, 110		C-GENPLANT	X	X	X	Total O&M Labor less A&G		(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
153	GENERAL PLANT CONTRA			C-GENPLANT	X	-	X	Total O&M Labor less A&G		(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
154	INTANGIBLE PLANT												
155	INTANGILBE PLANT	111, 115		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
156	**WORKING CAPITAL REQUIREMENTS**												
157	FUEL INVENTORY	151		C-FUEL	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
158	MATERIALS & SUPPLIES	154, 163	8/										
159	PRODUCTION - DEMAND	154, 163		C-MSPROD	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
160	TRANSMISSION	154, 163		C-MSTRAN	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
161	DISTRIBUTION - PRIMARY												
162	OVERHEAD LINES - DEMAND	154, 163		C-DPOHL	X	-	-	-	Class NCP	(E)	D-06	J-D-06	CC-D-06
163	OVERHEAD LINES - CUSTOMER	154, 163		C-DPOHL	-	-	X	-	Customers	(E)	C-01	J-C-01	CC-C-01
164	UNGRD LINES - DEMAND	154, 163		C-DPUGL	X	-	-	-	Class NCP	(E)	D-07	J-D-07	CC-D-07
165	UNGRD LINES - CUSTOMER	154, 163		C-DPUGL	-	-	X	-	Customers	(E)	C-02	J-C-02	CC-C-02
166	DISTRIBUTION - SECONDARY												
167	OVHD LINES - DEMAND	154, 163		C-DSOHL	X	-	-	-	Sum NCP	(E)	D-10	J-D-10	CC-D-10
168	OVHD LINES - CUSTOMER	154, 163		C-DSOHL	-	-	X	-	Customers	(E)	C-03	J-C-03	CC-C-03
169	UNGRD LINES - DEMAND	154, 163		C-DSUGL	X	-	-	-	Sum NCP	(E)	D-11	J-D-11	CC-D-11
170	UNGRD LINES - CUSTOMER	154, 163		C-DSUGL	-	-	X	-	Customers	(E)	C-04	J-C-04	CC-C-04
171	OVHD LINE TRANSFRM - DEMAND	154, 163		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	D-12	J-D-12	CC-D-12
172	OVHD LINE TRANSFRMS - CUSTOMER	154, 163		C-DSOHT	-	-	X	-	Customers	(E)	C-05	J-C-05	CC-C-05
173	UNGRD LINE TRANSFRMS - DEMAND	154, 163		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	D-13	J-D-13	CC-D-13
174	UNGRD LINE TRANSFRMS - CUSTOMER	154, 163		C-DSUGT	-	-	X	-	Customers	(E)	C-06	J-C-06	CC-C-06
175	OVHD SERVICES - DEMAND	154, 163		C-DSOHS	X	-	-	-	Sum NCP	(E)	D-14	J-D-14	CC-D-14
176	OVERHEAD SERVICES - CUSTOMER	154, 163		C-DSOHS	-	-	X	-	Customers	(E)	C-07	J-C-07	CC-C-07
177	UNGRD SERVICES - DEMAND	154, 163		C-DSUGS	X	-	-	-	Sum NCP	(E)	D-15	J-D-15	CC-D-15
178	UNGRD SERVICES - CUSTOMER	154, 163		C-DSUGS	-	-	X	-	Customers	(E)	C-08	J-C-08	CC-C-08
179	LEASED PROPERTY	154, 163		C-DSLEASED	-	-	X	-	Direct	(E)	C-09	J-C-09	CC-C-09
180	STREET LIGHTING	154, 163		C-DSLIGHTING	-	-	X	-	Direct	(E)	C-10	J-C-10	CC-C-10
181	DISTRIBUTION OTHER												
182	METERS	154, 163		C-DSMETERS	-	-	X	Meter counts & cost		(E)	C-11	J-C-11	CC-C-11
183	PRODUCTION - DEMAND	154, 163		C-DOPROD	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
184	DISTRIBUTION BULK DELIVERY			C-DODBD	X	-	-	NCP	Class NCP	(E)	D-03	J-D-03	CC-D-03
185	DISTRIBUTION SUBSTATIONS	154, 163		C-DODSUB	X	-	-	-	Class NCP	(E)	D-05	J-D-05	CC-D-05
186	DIST BULK DEL SPECIFIC ASSIGN			C-DODBDSA	X	-	-	Direct	-	(E)	D-04	J-D-04	CC-D-04

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

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187	DIST PRIMARY SPECIFIC ASSIGN	154, 163		C-DODPSA	X	-	-	Direct	-	(E)	D-08	J-D-08	CC-D-08
188	PREPAYMENTS	165.1, 165.8		C-EPLANTIS	X	X	X	Plant		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
189	PREPAYMENTS - PENSION ASSET	18230.6015, 21900.0003, 22830.20008/9/11		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	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)	OMLXAG	J-OMLXAG	CC-OMLXAG
191	PREPAYMENTS - SBPC CONTRACT	18640.6023		C-SBPC	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
192	CASH WORKING CAPITAL	-	9/										
193	O&M EXPENSES	-											
194	FUEL	-		C-OMFUEL	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
195	PURCHASED POWER	-		C-OMPPOWER	X	X	-	Total Purchased Power Exp		(I)	OMPPOWER	J-OMPPOWER	CC-OMPPOWER
196	PAYROLL	-		C-OMLABOR	X	X	X	Total O&M Labor		(I)	OMLABOR	J-OMLABOR	CC-OMLABOR
197	OTHER O&M	-		C-OMEXPCWC	X	X	X	O&M Expense CWC		(I)	OMEXPCWC	J-OMEXPCWC	CC-OMEXPCWC
198	PROPERTY TAXES	-		C-PROPTAX	X	X	X	Total Propert Taxes		(I)	PROPTAX	J-PROPTAX	CC-PROPTAX
199	PAYROLL TAXES	-		C-OMLABOR	X	X	X	Total O&M Labor		(I)	OMLABOR	J-OMLABOR	CC-OMLABOR
200	AIR QUALITY EMISSION TAX	-		C-ENVTAX	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
201	INCOME TAXES	-		C-RATEBASE	X	X	X	Rate Base		(I)	INCTAX	J-INCTAX	CC-INCTAX
202	INCOME TAXES (INCREASE)	-		C-INCTAX	X	X	X	-	Rate Base	(I)	MN	J-MN	CC-MN
203	PAYROLL TAXES WITHHELD	-		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
204	SALES TAX COLLECTIONS	-		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
205	MINNESOTA WIND PRODUCTION TAX			C-WINDTAX	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
206													
207	**ASSET RETIREMENT OBLIGATION**	23000, 18230		C-ARO	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
208	**WORKERS COMP DEPOSIT**	18640.0093		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLAXAG	J-OMLAXAG	CC-OMLAXAG
209	**UNAMORTIZED WPPI TRANSM AMORT**	25300.9030		C-WPPI	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
210	**UNAMORTIZED UMWI TRANSACTION COST**	18230.3003		C-UMWI	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
211	**CUSTOMER ADVANCES**												
212	PRIMARY OVHD LINES - DEM	252		C-DPOHL	X	-	-	-	Class NCP	(E)	D-06	J-D-06	CC-D-06
213	PRIMARY OVHD LINES - CUST	252		C-DPOHL	-	-	X	-	Customers	(E)	C-01	J-C-01	CC-C-01
214	SECONDARY OVHD LINES - DEM	252		C-DSOHL	X	-	-	-	Sum NCP	(E)	D-10	J-D-10	CC-D-10
215	SECONDARY OVHD LINES - CUST	252		C-DSOHL	-	-	X	-	Customers	(E)	C-03	J-C-03	CC-C-03
216	**CUSTOMER DEPOSITS**	235		C-DEPOSITS	X	-	X	Total Customer Advances		(I)	DEPOSITS	J-DEPOSITS	CC-DEPOSITS
217	**OTHER DEFERRED CREDITS - HIBBARD**			C-STEAM	X	-	-	Steam PIS		(I)	STEAM	J-STEAM	CC-STEAM
218	**WIND PERFORMANCE DEPOSIT**			C-WIND	X	-	-	Wind PIS		(I)	WIND	J-WIND	CC-WIND
219	**SPECIFIED DEFERRED CREDITS**												
220	ACCUMULATED DEFERRED INCOME TAXES												
221	ACCOUNTS 281, 282, 283												
222	STEAM	281-3		C-STEAM	X	-	-	Steam PIS		(I)	STEAM	J-STEAM	CC-STEAM
223	HYDRO	281-3		C-HYDRO	X	X	-	Hydo PIS		(I)	HYDRO	J-HYDRO	CC-HYDRO
224	WIND	281-3		C-WIND	X	-	-	Wind PIS		(I)	WIND	J-WIND	CC-WIND
225	SOLAR	281-3		C-SOLAR	X	-	-	Solar PIS		(I)	SOLAR	J-SOLAR	CC-SOLAR
226	TRANSMISSION	281-3		C-TRAN	X	-	-	Trans PIS		(I)	TRAN	J-TRAN	CC-TRAN
227	DISTRIBUTION	281-3		C-DIST	X	-	X	Disttribution PIS		(I)	DIST	J-DIST	CC-DIST
228	GENERAL	281-3		C-GENPLANT	X	X	X	General PIS		(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
229	**SPECIFIED DEFERRED DEBITS**												
230	ACCUMULATED DEFERRED INCOME TAXES												
231	ACCOUNT 190												
232	STEAM	190		C-STEAM	X	-	-	Steam PIS		(I)	STEAM	J-STEAM	CC-STEAM
233	HYDRO	190		C-HYDRO	X	X	-	Hydo PIS		(I)	HYDRO	J-HYDRO	CC-HYDRO
234	WIND	190		C-WIND	X	-	-	Wind PIS		(I)	WIND	J-WIND	CC-WIND
235	SOLAR	190		C-SOLAR	X	-	-	Solar PIS		(I)	SOLAR	J-SOLAR	CC-SOLAR
236	TRANSMISSION	190		C-TRAN	X	-	-	Trans PIS		(I)	TRAN	J-TRAN	CC-TRAN
237	DISTRIBUTION	190		C-DIST	X	-	X	Disttribution PIS		(I)	DIST	J-DIST	CC-DIST
238	GENERAL	190		C-GENPLANT	X	X	X	General PIS		(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
239													
240													
241	**INCOME STATEMENT**												
242	**ELECTRIC OPERATING REVENUES**												
243	SALES OF ELECTRICITY												
244	SALES BY RATE CLASS	440-447		C-RSALES	X	X	X	Direct	Direct	(I)	RSALES	J-RSALES	CC-RSALES
245	DUAL FUEL DEMAND	440-443		C-RDUALFUEL	X	-	-	-	P & A	(E)	D-01	J-MN	CC-D-01

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

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246	DUAL FUEL ENERGY	440-443		C-RDUALFUEL	-	X	-	-	E8760	(E)	E-01	J-MN	CC-E-01
247	INTERSYSTEM SALES DEMAND	443		C-RISSALES	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
248	INTERSYSTEM SALES ENERGY	443		C-RISSALES	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
249	SALES FOR RESALE DEMAND	447		C-RISSALES	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
250	SALES FOR RESALE ENERGY	447		C-RRESALE	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
251	OTHER OPERATING REVENUE												
252	A/C 4561, 4564, 4569 PROD - DEMAND	456		C-PROD	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
253	A/C 4569 PRODUCTION - ENERGY	456		C-PROD	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
254	A/C 454, 4562, 4569 - TRANSMISSION	454, 456		C-TRAN	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
255	A/C 450-4569 DISTRIBUTION												
256	DISTRIBUTION - PRIMARY												
257	OVERHEAD LINES - DEMAND	450, 456		C-DPOHL	X	-	-	-	Class NCP	(E)	D-06	J-D-06	CC-D-06
258	OVERHEAD LINES - CUSTOMER	450, 456		C-DPOHL	-	-	X	-	Customers	(E)	C-01	J-C-01	CC-C-01
259	UNGRD LINES - DEMAND	450, 456		C-DPUGL	X	-	-	-	Class NCP	(E)	D-07	J-D-07	CC-D-07
260	UNGRD LINES - CUSTOMER	450, 456		C-DPUGL	-	-	X	-	Customers	(E)	C-02	J-C-02	CC-C-02
261	DISTRIBUTION - SECONDARY												
262	OVHD LINES - DEMAND	450, 456		C-DSOHL	X	-	-	-	Sum NCP	(E)	D-10	J-D-10	CC-D-10
263	OVHD LINES - CUSTOMER	450, 456		C-DSOHL	-	-	X	-	Customers	(E)	C-03	J-C-03	CC-C-03
264	UNGRD LINES - DEMAND	450, 456		C-DSUGL	X	-	-	-	Sum NCP	(E)	D-11	J-D-11	CC-D-11
265	UNGRD LINES - CUSTOMER	450, 456		C-DSUGL	-	-	X	-	Customers	(E)	C-04	J-C-04	CC-C-04
266	OVHD LINE TRANSFRM - DEMAND	450, 456		C-DSOHT	X	-	-	-	Avg Class & Sum NCP	(E)	D-12	J-D-12	CC-D-12
267	OVHD LINE TRANSFRMS - CUSTOMER	450, 456		C-DSOHT	-	-	X	-	Customers	(E)	C-05	J-C-05	CC-C-05
268	UNGRD LINE TRANSFRMS - DEMAND	450, 456		C-DSUGT	X	-	-	-	Avg Class & Sum NCP	(E)	D-13	J-D-13	CC-D-13
269	UNGRD LINE TRANSFRMS - CUSTOMER	450, 456		C-DSUGT	-	-	X	-	Customers	(E)	C-06	J-C-06	CC-C-06
270	OVHD SERVICES - DEMAND	450, 456		C-DSOHS	X	-	-	-	Sum NCP	(E)	D-14	J-D-14	CC-D-14
271	OVERHEAD SERVICES - CUSTOMER	450, 456		C-DSOHS	-	-	X	-	Customers	(E)	C-07	J-C-07	CC-C-07
272	UNGRD SERVICES - DEMAND	450, 456		C-DSUGS	X	-	-	-	Sum NCP	(E)	D-15	J-D-15	CC-D-15
273	UNGRD SERVICES - CUSTOMER	450, 456		C-DSUGS	-	-	X	-	Customers	(E)	C-08	J-C-08	CC-C-08
274	LEASED PROPERTY	450, 456		C-DSLEASED	-	-	X	-	Direct	(E)	C-09	J-C-09	CC-C-09
275	STREET LIGHTING	450, 456		C-DSLIGHTING	-	-	X	-	Direct	(E)	C-10	J-C-10	CC-C-10
276	DISTRIBUTION OTHER												
277	METERS	450, 456		C-DSMETERS	-	-	X	Meter counts & cost		(E)	C-11	J-C-11	CC-C-11
278	PRODUCTION - DEMAND	450, 456		C-DOPROD	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
279	DISTRIBUTION BULK DELIVERY			C-DODBD	X	-	-	NCP	Class NCP	(E)	D-03	J-D-03	CC-D-03
280	DISTRIBUTION SUBSTATIONS	450, 456		C-DODSUB	X	-	-	-	Class NCP	(E)	D-05	J-D-05	CC-D-05
281	DIST BULK DEL SPECIFIC ASSIGN			C-DODBDSA	X	-	-	Direct	-	(E)	D-04	J-D-04	CC-D-04
282	DIST PRIMARY SPECIFIC ASSIGN	450, 456		C-DODPSA	X	-	-	Direct	-	(E)	D-08	J-D-08	CC-D-08
283	GENERAL PLANT	450, 456		C-GENPLANT	X	X	X	General Plant		(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
284	DISPOSITION OF ALLOWANCES	450, 456		C-RDISPALL	-	X	-	-	E8760	(E)	E-01	J-E-01MN	CC-E-01MN
285	**OPERATION & MAINTENANCE EXPENSE**												
286	STEAM PRODUCTION												
287	DEMAND	500-3, 505/6, 511, 514		C-OMSTEAM	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
288	ENERGY	510, 512-3		C-OMSTEAM	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
289	HYDRO PRODUCTION												
290	DEMAND	535, 537-9, 541-2		C-OMHYDRO	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
291	ENERGY	543-5		C-OMHYDRO	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
292	WIND PRODUCTION	546-554		C-OMWIND	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
293	TRANSMISSION	560-2, 565-571, 573		C-OMTRAN	X	-	-	12 CP	P & A	(I)	OMTRAN	J-OMTRAN	CC-OMTRAN
294	DISTRIBUTION												
295	METERS	586, 597		C-OMDMETERS	-	-	X	Meter counts & cost		(E)	C-11	J-C-11	CC-C-11
296	OTHER DISTRIBUTION	580-5, 587-590, 592-8		C-OMDXMETERS	X	-	X	Dist PIS, Excl Meters		(I)	OMDXMETERS	J-OMDXMETERS	CC-OMDXMETERS
297	OTHER POWER SUPPLY												
298	PRODUCTION DEMAND	556-7		C-OMPOWER	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
299	PURCHASED POWER												
300	DEMAND	555		C-OMPPOWER	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
301	ENERGY	555		C-OMPPOWER	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
302	FUEL	501		C-OMFUEL	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
303	CUSTOMER ACCOUNTING	901-4		C-OMCACCOUNT	-	-	X	Expenses & Labor ratios		(E)	C-12	J-C-12	CC-C-12
304	CUSTOMER ACCOUNTING CREDIT CARDS	903.1		C-OMCACCOUNT	-	-	X	Expenses & Labor ratios		(E)	C-15	J-C-15	CC-C-15
305	CUSTOMER SERVICE & INFORMATION	907-10		C-OMCSERVICE	-	-	X	Expenses & Labor ratios		(E)	C-14	J-C-14	CC-C-14
306	CONSERV IMPROVE PROG - ENERGY	90806.0000		C-OMCIP	-	X	-	-	CCRC MWh	(E)	E-02	J-E-02	CC-E-02
307	SALES	913		C-OMSALES	-	-	X	Expenses & Labor ratios		(E)	C-13	J-C-13	CC-C-13
308	ADMINISTRATIVE & GENERAL												

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 / Number of Allocator	Name / Number of Jurisdictional Allocator 12/	Name / Number of Customer Class Allocator
309	PROPERTY INSURANCE	924		C-EPLANTIS	X	X	X		Utility Plant In Service	(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
310	REGULATORY EXPENSES - MISC	928		C-EPLANTIS	X	X	X		Utility Plant In Service	(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
311	REGULATORY EXPENSES - MIS0	928		C-REGEXPMISO	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
312	ADVERTISING	930.1		C-OMLXAG	X	X	X		Total O&M Labor less A&G	(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
313	FRANCHISE REQUIREMENTS	927		C-RATEBASE	X	X	X	-	Retail Rate Base	(I)	RATEBASEMN	J-MN	CC-RATEBASEMN
314	OTHER ADMIN & GENERAL	920-1, 923, 925-6, 930.2		C-OMLXAG	X	X	X		Total O&M Labor less A&G	(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
315	CHARITABLE CONTRIBUTIONS	426.1		C-OMLXAG	X	X	X		Total O&M Labor less A&G	(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
316	INTEREST ON CUSTOMER DEPOSITS	43100.1001, 43100.1002		C-RATEBASE	X	X	X	Rate Base	Retail Rate Base	(I)	RATEBASEMN	J-MN	CC-RATEBASEMN
317	**DEPRECIATION EXPENSE**												
318	STEAM	403		C-STEAM	X	-	-		Steam PIS	(E)	D-01	J-D-01	CC-D-01
319	STEAM CONTRA			C-STEAM	X	-	-	Direct	P & A	(E)	Contra-16	J-Contra-16	CC-D-01
320	HYDRO DEMAND	403		C-HYDRO	X	-	-		Hydo PIS	(E)	D-01	J-D-01	CC-D-01
321	HYDRO ENERGY			C-HYDRO	-	X	-		Hydo PIS	(E)	E-01	J-E-01	CC-E-01
322	HYDRO CONTRA			C-HYDRO	X	-	-	Direct	P & A	(E)	Contra-17	J-Contra-17	CC-D-01
323	WIND	403		C-HYDRO	X	-	-		Wind PIS	(E)	D-01	J-D-01	CC-D-01
324	WIND CONTRA			C-HYDRO	X	-	-	Direct	P & A	(E)	Contra-18	J-Contra-18	CC-D-01
325	SOLAR	403		C-SOLAR	X	-	-		Solar PIS	(E)	D-01	J-D-01	CC-D-01
326	TRANSMISSION	403		C-TRAN	X	-	-		Trans PIS	(E)	D-02	J-D-02	CC-D-02
327	TRANSMISSION CONTRA			C-TRAN	X	-	-	Direct	P & A	(E)	Contra-20	J-Contra-20	CC-D-02
328	DISTRIBUTION	403		C-DIST	X	-	X		Dist PIS	(E)	DIST	J-DIST	CC-DIST
329	DISTRIBUTION CONTRA			C-DIST	X	-	X		Dist PIS	(E)	DIST	J-DIST	CC-DIST
330	GENERAL PLANT	403		C-GENPLANT	X	X	X		General PIS	(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
331	GENERAL PLANT CONTRA	403		C-GENPLANT	X	X	X		General PIS	(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
332	**AMORTIZATION EXPENSE**												
333	**INTANGIBLE PLANT**	404		C-GENPLANT	X	X	X		General Plant	(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
334	**UMWI**	406, 407.3		C-UMWI	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
335	**ARO ACCERTION**	411.1		C-ARO	X	-	-	12 CP	P & A	(E)	D-01	J-D-01	CC-D-01
336	**2020 RATE CASE EXPENSE AMORTIZATION**	928		C-RATEBASE	X	X	X	-	Retail Rate Base	(I)	RATEBASEMN	J-MN	CC-RATEBASE
337	**PROPERTY TAXES**												
338	STEAM	408.1		C-STEAM	X	-	-		Steam PIS	(I)	STEAM	J-STEAM	CC-STEAM
339	HYDRO	408.1		C-HYDRO	X	X	-		Total Hydo PIS	(I)	HYDRO	J-HYDRO	CC-HYDRO
340	WIND	408.1		C-WIND	X	-	-		Wind PIS	(I)	WIND	J-WIND	CC-WIND
341	SOLAR	408.1		C-SOLAR	X	-	-		Solar PIS	(I)	WIND	J-WIND	CC-WIND
342	TRANSMISSION	408.1		C-TRAN	X	-	-		Transmission PIS	(I)	TRAN	J-TRAN	CC-TRAN
343	DISTRIBUTION	408.1		C-DIST	X	-	X		Distribution PIS	(I)	DIST	J-DIST	CC-DIST
344	GENERAL PLANT	408.1		C-GENPLANT	X	X	X		Total General PIS	(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
345	**PAYROLL TAXES**												
346	STEAM	408.1		C-OMLSTEAM	X	X	-		O&M Steam Labor	(I)	OMLSTEAM	J-OMLSTEAM	CC-OMLSTEAM
347	HYDRO	408.1		C-OMLHYDRO	X	X	-		O&M Hydro Labor	(I)	OMLHYDRO	J-OMLHYDRO	CC-OMLHYDRO
348	WIND	408.1		C-OMLWIND	X	X	-		O&M Wind Labor	(I)	OMLWIND	J-OMLWIND	CC-OMLWIND
349	SOLAR	408.1		C-OMLSOLAR	X	X	-		O&M Solar Labor	(I)	OMLSOLAR	J-OMLSOLAR	CC-OMLSOLAR
350	TRANSMISSION	408.1		C-OMLTRAN	X	-	-		O&M Transmission Labor	(I)	OMLTRAN	J-OMLTRAN	CC-OMLTRAN
351	DISTRIBUTION	408.1		C-OMLDIST	X	-	X		O&M Distribution Labor	(I)	OMLDIST	J-OMLDIST	CC-OMLDIST
352	OTHER POWER SUPPLY	408.1		C-OMLPOWER	X	-	-		O&M Other Power Supply Labor	(I)	OMLPOWER	J-OMLPOWER	CC-OMLPOWER
353	FUEL	408.1		C-OMLFUEL	-	X	-		O&M Fuel Labor	(I)	OMLFUEL	J-OMLFUEL	CC-OMLFUEL
354	CUSTOMER ACCOUNTING	408.1		C-OMLCACCOUNT	-	-	X		Expenses & Labor ratios	(E)	C-12	J-C-12	CC-C-12
355	CUSTOMER SERVICE & INFO	408.1		C-OMLCSERVICE	-	-	X		Expenses & Labor ratios	(E)	C-14	J-C-14	CC-C-14
356	SALES	408.1		C-OMLSALES	-	-	X		Expenses & Labor ratios	(E)	C-13	J-C-13	CC-C-13
357	ADMIN & GEN	408.1		C-OMLAG	X	X	X		Total O&M Labor less A&G	(I)	OMLAG	J-OMLAG	CC-OMLAG
358	**AIR QUALITY EMISSION - PROD ENERGY**	408.1		C-AIRTAX	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
359	**MINNESOTA WIND PRODUCTION TAX**	408.1		C-WINDTAX	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
360	**MINNESOTA SOLAR PRODUCTION TAX**	408.1		C-SOLARTAX	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
361	**ADDITIONS AND DEDUCTIONS TO INCOME FOR TAX**												
362	ACCRUED POST EMPLOYMENT BENEFITS -FAS 112 OPERATING												
363	ACCRUED VACATION	various		C-OMLXAG	X	X	X		Total O&M Labor less A&G	(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
364	ARO ACCRETION	various		C-OMLXAG	X	X	X		Total O&M Labor less A&G	(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
365	ARO AMORTIZATION	various		C-STEAM	X	-	-		Steam Plant	(I)	STEAM	J-STEAM	CC-STEAM
366	BOND ISSUE COSTS (NCL)	various		C-RATEBASE	X	X	X		Total Average Rate Base	(I)	RATEBASE	J-RATEBASE	CC-RATEBASE
367	BOSWELL TRANSMISSION AGREEMENT	various		C-TRAN	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
368	CAPITALIZED OVERHEADS	various		C-OMLXAG	X	X	X		Total O&M Labor less A&G	(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
369	CONSERVATION IMPROVEMENT PROJECT	various		C-OMCIP	-	X	-	-	CCRC MWh	(E)	E-02	J-E-02	CC-E-02
370	CONTRIBUTION IN AID OF CONSTRUCTION	various		C-DSOHL	X	X	-		Sum NCP & Customers	(E)	D-10 / C-03	J-D-10 / C-D-03	CC-D-10 / CC_C-03

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 / Number of Allocator	Name / Number of Jurisdictional Allocator 12/	Name / Number of Customer Class Allocator
371	COST TO RETIRE	various		C-EPLANTIS	X	X	X	Utility Plant In Service		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
	DEFERRED NON-QUALIFIED PLANS (NCA)	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
372	DEFERRED NON-QUALIFIED PLANS - OPERATING	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
373	DIRECTOR FEES -DEFERRED	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
374	DUES	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
375	EIP DEATH BENEFIT	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
376	EPA NOV	various		C-STEAM	X	-	-	Steam Plant		(I)	STEAM	J-STEAM	CC-STEAM
377	ESPP DISQUALIFING DISPOSITION	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
378	FAS 158 - MONTHLY	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
379	FAS 158 - OCI ADJUSTMENT	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
380	FUEL CLAUSE ADJUSMENT	various		C-OMFUEL	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
381	FUEL TAX CREDIT	various		C-OMFUEL	-	X	-	E-01	E8760	(E)	E-01	J-E-01	CC-E-01
382	INT LONG TERM DEBT (INTEREST SYNCHRONIZAT	various	10/	C-RATEBASE	X	X	X	Total Average Rate Base		(I)	RATEBASE	J-RATEBASE	CC-RATEBASE
383	MEALS AND ENTERTAINMENT	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
384	MEDICAL CLAIMS (CA)	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
385	MEDICARE SUBSIDY	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
386	MISO RESERVE	various		C-REGEXPMISO	X	-	-	12 CP	P & A	(E)	D-02	J-D-02	CC-D-02
387	ND ITC REGULATORY LIABILIY	various		C-WIND	X	-	-	Wind PIS		(I)	WIND	J-WIND	CC-WIND
388	NONDEDUCTIBLE PARKING	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	RATEBASE	J-RATEBASE	CC-RATEBASE
389	OPEB FAS 106 OPERATING	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
390	PENSION EXPENSE - OPERATING (NCA)	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
391	PERFORMANCE SHARES - FAW 123R	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
392	PENALTIES	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	RATEBASE	J-RATEBASE	CC-RATEBASE
393	POLITICAL ACTIVITIES	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
394	PREPAID BISON EASEMENTS	various		C-WIND	X	-	-	Wind PIS		(I)	WIND	J-WIND	CC-WIND
395	PREPAID INSURANCE	various		C-EPLANTIS	X	X	X	Utility Plant In Service		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
396	PROPERTY TAXES	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	PROPTAX	J-PROPTAX	CC-PROPTAX
397	RATE CASE RESERVE	various		C-RATEBASE	X	X	X	Total Average Rate Base		(I)	RATEBASE	J-MN	CC-RATEBASEMN
398	RESTRICTED STOCK	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
399	RETAIL RATE CASE EXPENSE	various		C-RATEBASE	X	X	X	Total Average Rate Base - Retail		(I)	RATEBASE	J-MN	CC-RATEBASEMN
400	RETIREMENTS	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
401	RSOP	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
402	SAWTOOTH LAND SALE	various		C-EPLANTIS	X	X	X	Utility Plant In Service		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
403	SEC 162(M) LIMITATION	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
404	SECTION 174	various		C-OMLXAG	X	X	X	Total O&M Labor less A&G		(I)	OMLXAG	J-OMLXAG	CC-OMLXAG
405	TAX/BOOK DEPRECIATION DIFFERENCE	various		C-EPLANTIS	X	X	X	Utility Plant In Service		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
406	TAX CAPITALIZED INTEREST	various		C-EPLANTIS	X	X	X	Utility Plant In Service		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
407	TAX GAIN	various		C-EPLANTIS	X	X	X	Utility Plant In Service		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
408	UNREALIZED BOOK LOSSES	various		C-RATEBASE	X	X	X	Total Average Rate Base - Retail		(I)	RATEBASE	J-RATEBASE	CC-RATEBASE
409	**INCOME TAXES**												
410	STATE CURRENT INCOME TAX												
411	ADJ NET INCOME	-			X	X	X	CCOSS CALCULATION		-	-		-
412	STATE NOL UTLIZED				X	X	X	Utility Plant In Service		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
413	STATE DEPRECIATION MODIFICATION	-			X	X	X	Utility Plant In Service		(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
414	STATE NET TAXABLE INCOME	-			X	X	X	CCOSS CALCULATION					

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 / Number of Allocator	Name / Number of Jurisdictional Allocator 12/	Name / Number of Customer Class Allocator
415	STATE TAX AT 9.8 PERCENT	-			X	X	X		CCOSS CALCULATION				
416	STATE TAX CREDITS	-			X	X	X		Utility Plant In Service	(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
417	CORRECTION TO PRIOR YEARS				X	X	X		Utility Plant In Service	(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
418	STATE MINIMUM TAX				X	X	X		Utility Plant In Service	(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
419	FEDERAL CURRENT INCOME TAX												
420	ADJ NET INCOME	-			X	X	X		CCOSS CALCULATION	-	-		-
421	STATE TAX DEDUCTION	-			X	X	X		Calculated Above	-	-		-
422	FEDERAL NOL UTILIZED	-			X	X	X		Utility Plant In Service	(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
423	FEDERAL NET TAXABLE INCOME	-			X	X	X		CCOSS CALCULATION	-	-		-
424	FEDERAL TAX AT 21 PERCENT	-			X	X	X		CCOSS CALCULATION		-		-
425	TAX CREDITS	-			X	X	X		Utility Plant In Service	(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
426	CORRECTION TO PRIOR YEARS				X	X	X		Utility Plant In Service	(I)	EPLANTIS	J-EPLANTIS	CC-EPLANTIS
427	**PROVISION FOR DEFERRED INCOME TAX**												
428	ACCOUNT 410.1												
429	STEAM	410.1		C-STEAM	X	-	-		Steam PIS	(I)	STEAM	J-STEAM	CC-STEAM
430	HYDRO	410.1		C-HYDRO	X	X	-		Hydro PIS	(I)	HYDRO	J-HYDRO	CC-HYDRO
431	WIND	410.1		C-WIND	X	-	-		Wind PIS	(I)	WIND	J-WIND	CC-WIND
432	SOLAR	410.1		C-SOLAR	X	-	-		Solar PIS	(I)	SOLAR	J-SOLAR	CC-SOLAR
433	TRANSMISSION	410.1		C-TRAN	X	-	-		Transmission PIS	(I)	TRAN	J-TRAN	CC-TRAN
434	DISTRIBUTION	410.1		C-DIST	X	-	X		Distribution PIS	(I)	DIST	J-DIST	CC-DIST
435	GENERAL	410.1		C-GENPLANT	X	X	X		General PIS	(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
436	**PROVISION FOR DEFERRED INCOME TAX - CREDIT**												
437	ACCOUNT 411.1												
438	STEAM	411.1		C-STEAM	X	-	-		Steam PIS	(I)	STEAM	J-STEAM	CC-STEAM
439	HYDRO	411.1		C-HYDRO	X	X	-		Hydro PIS	(I)	HYDRO	J-HYDRO	CC-HYDRO
440	WIND	411.1		C-WIND	X	-	-		Wind PIS	(I)	WIND	J-WIND	CC-WIND
441	SOLAR	411.1		C-SOLAR	X	-	-		Solar PIS	(I)	SOLAR	J-SOLAR	CC-SOLAR
442	TRANSMISSION	411.1		C-TRAN	X	-	-		Transmission PIS	(I)	TRAN	J-TRAN	CC-TRAN
443	DISTRIBUTION	411.1		C-DIST	X	-	X		Distribution PIS	(I)	DIST	J-DIST	CC-DIST
444	GENERAL	411.1		C-GENPLANT	X	X	X		General PIS	(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
445	**INVESTMENT TAX CREDIT**												
446	ACCOUNT 411.4												
447	STEAM	411.4		C-STEAM	X	-	-		Steam PIS	(I)	STEAM	J-STEAM	CC-STEAM
448	HYDRO	411.4		C-HYDRO	X	X	-		Hydro PIS	(I)	HYDRO	J-HYDRO	CC-HYDRO
449	WIND	411.4		C-WIND	X	-	-		Wind PIS	(I)	WIND	J-WIND	CC-WIND
450	SOLAR	411.4		C-SOLAR	X	-	-		Solar PIS		SOLAR	J-SOLAR	CC-SOLAR
451	TRANSMISSION	411.4		C-TRAN	X	-	-		Transmission PIS	(I)	TRAN	J-TRAN	CC-TRAN
452	DISTRIBUTION	411.4		C-DIST	X	-	X		Distribution PIS	(I)	DIST	J-DIST	CC-DIST
453	GENERAL	411.4		C-GENPLANT	X	X	X		General PIS	(I)	GENPLANT	J-GENPLANT	CC-GENPLANT
454	**ALLOWANCE FUNDS DURING CONSTRUCTION**												
455	STEAM	419.1, 432		C-STEAMCWIP	X	-	-		Total CWIP Steam	(I)	STEAMCWIP	J-STEAMCWIP	CC-STEAMCWIP
456	HYDRO	419.1, 432		C-HYDROCWIP	X	X	-		Total CWIP Hydro	(I)	HYDROCWIP	J-HYDROCWIP	CC-HYDROCWIP
457	WIND	419.1, 432		C-WINDCWIP	X	-	-		Total CWIP Wind	(I)	WINDCWIP	J-WINDCWIP	CC-WINDCWIP
458	SOLAR	419.1, 432		C-SOLARCWIP	X	-	-		Total CWIP Solar	(I)	SOLARCWIP	J-SOLARCWIP	CC-SOLARCWIP
459	TRANSMISSION	419.1, 432		C-TRANCWIP	X	-	-		Total CWIP Transmission	(I)	TRANCWIP	J-TRANCWIP	CC-TRANCWIP
460	DISTRIBUTION	419.1, 432		C-DISTCWIP	X	-	X		Total CWIP Distribution	(I)	DISTCWIP	J-DISTCWIP	CC-DISTCWIP
461	GENERAL	419.1, 432		C-GENPLANTCWIP	X	X	X		Total CWIP General Plant	(I)	GENPLANTCWIP	J-GENPLANTCWIP	CC-GENPLANTCWIP
462	INTANGIBLE PLANT	419.1, 432		C-INTPLANTCWIP	X	X	X		Total CWIP Intangible Plant	(I)	INTPLANTCWIP	J-INTPLANTCWIP	CC-INTPLANTCWIP

Notes:
1/ All items are generally presented in the same order as in MP's CCOSS.
2/ All regulated Hydro projects and assets at reservoir facilities only are subfunctionalized as production energy, remaining plant is demand.
3/ Step-up transformers at generating stations booked in transmission plant are subfuctionalized as production demand.
4/ Refer to MP's COSS Guide for description of treatment of distribution plant.
5/ Step-up transformers at generating stations booked in distribution plant are subfuctionalized as production demand.
6/ Distribution Bulk Delivery are 23, 34 and 46 kV facilities that serve FERC and retail jurisdictional customers.
7/ Specific Distribution 14 kV facilities and 23, 34, and 46 kV taps that serve FERC jurisdictional customers.
8/ Subfunctionalized to production, transmission and distribution on most recent calender year actual amounts. Distribution subsequently subfunctionalized/classifed on PIS ratios.
9/ Calculated
10/ Calculated as part of interest syncronization. Average rate base multiplied by cost of long term debt.
11/ Refer to the attached Table 5 for the Classification Allocator bases and Table 6 for the Classification Allocator Factors.
12/ Refer to Volume 3, Direct Schedules B-15 to B-18 and Direct Schedules C-13 to C-16 for the Jurisdictional Allocator Bases and Factors

Table 5 Classification Allocator Bases

Allocator Type	Classification Allocator Bases	Code	Customer	Demand	Energy	Total Company
Calculated	Classification - Accumulated Depreciation - Distribution Excluding Contra	C-ADDXCONTRA	$ (102,731,795)	$ (209,428,215)	$ -	$ (312,160,011)
Calculated	Classification - Adjusted Net Income Before Taxes	C-ADJNETINC	$ 13,216,036	$ (64,519,993)	$ 147,907,827	$ 96,603,869
Internal	Classification - Air Quality Emission Tax	C-AIRTAX	$ -	$ -	$ (1,068,302)	$ (1,068,302)
Internal	Classification - Asset Retirement Obligation	C-ARO	$ -	$ -	$ -	$ -
External	Classification - BEC4 Rider Revenue	C-BEC4	$ -	$ -	$ -	$ -
Internal	Classification - Cloquet Energy Center TG5	C-CEC	$ -	$ -	$ -	$ -
External	Classification - Conservation Improvement Program	C-CIP	$ -	$ -	$ -	$ -
Calculated	Classification - Distribution - CWIP Excluding Contra	C-DCWIPXCONTRA	$ 407,253	$ 1,082,016	$ -	$ 1,489,270
Internal	Classification - Defer Rate Case Expense	C-DEFRCE	$ -	$ -	$ -	$ -
Calculated	Classification - Customer Deposits	C-DEPOSITS	$ (935,367)	$ (1,326,507)	$ -	$ (2,261,874)
Calculated	Classification - Distribution	C-DIST	$ 213,078,896	$ 434,380,931	$ -	$ 647,459,828
Calculated	Classification - Distribution - CWIP	C-DISTCWIP	$ 407,253	$ 1,082,016	$ -	$ 1,489,270
Internal	Classification - Distribution Other - Distribution Bulk Delivery	C-DODBD	$ -	$ 110,102,200	$ -	$ 110,102,200
Internal	Classification - Distribution Other - Distribution Bulk Delivery Specific Assignment	C-DODBDSA	$ -	$ 1,116,056	$ -	$ 1,116,056
Internal	Classification - Distribution Other - Distribution Primary Specific Assignment	C-DODPSA	$ -	$ 729,556	$ -	$ 729,556
Internal	Classification - Distribution Other - Distribution Substations	C-DODSUB	$ -	$ 62,739,610	$ -	$ 62,739,610
Internal	Classification - Distribution Other - Production	C-DOPROD	$ -	$ 1,555,830	$ -	$ 1,555,830
Internal	Classification - Distribution Primary - Overhead Lines	C-DPOHL	$ 39,110,974	$ 65,046,081	$ -	$ 104,157,055
Internal	Classification - Distribution Primary - Underground Lines	C-DPUGL	$ 27,238,322	$ 85,316,729	$ -	$ 112,555,051
Internal	Classification - Distribution Secondary - Leased Property	C-DSLEASED	$ 2,093,166	$ -	$ -	$ 2,093,166
Internal	Classification - Distribution Secondary - Street Lighting	C-DSLIGHTING	$ 5,423,094	$ -	$ -	$ 5,423,094
Internal	Classification - Distribution Secondary - Meters	C-DSMETERS	$ 70,910,860	$ -	$ -	$ 70,910,860
Internal	Classification - Distribution Secondary - Overhead Lines	C-DSOHL	$ 24,221,923	$ 24,770,640	$ -	$ 48,992,563
Internal	Classification - Distribution Secondary - Overhead Services	C-DSOHS	$ 3,412,831	$ 2,936,622	$ -	$ 6,349,453
Internal	Classification - Distribution Secondary - Overhead Transformers	C-DSOHT	$ 13,431,657	$ 37,561,725	$ -	$ 50,993,382
Internal	Classification - Distribution Secondary - Underground Lines	C-DSUGL	$ 1,225,160	$ 10,521,337	$ -	$ 11,746,497
Internal	Classification - Distribution Secondary - Underground Services	C-DSUGS	$ 3,323,497	$ 8,731,261	$ -	$ 12,054,758
Internal	Classification - Distribution Secondary - Underground Transformers	C-DSUGT	$ 22,691,202	$ 23,261,009	$ -	$ 45,952,211
Calculated	Classification - Distribution Excluding Contra	C-DXCONTRA	$ 213,082,686	$ 434,388,656	$ -	$ 647,471,342
Calculated	Classification - Electric Plant in Service	C-EPLANTIS	$ 261,089,797	$ 3,927,857,752	$ 96,624,055	$ 4,285,571,604
Calculated	Classification - Federal Taxes	C-FEDTAX	$ 10,201,152	$ (84,068,534)	$ 132,776,429	$ 58,909,047
Internal	Classification - Fuel Inventory	C-FUEL	$ -	$ -	$ 3,299,159	$ 3,299,159
Calculated	Classification - General Plant	C-GENPLANT	$ 35,442,772	$ 137,724,986	$ 51,380,103	$ 224,547,860
Calculated	Classification - General Plant - CWIP	C-GENPLANTCWIP	$ 819,257	$ 3,183,503	$ 1,187,647	$ 5,190,407
Internal	Classification - Hydro Plant	C-HYDRO	$ -	$ 183,541,848	$ 27,024,390	$ 210,566,238
Internal	Classification - Hydro Plant - CWIP	C-HYDROCWIP	$ -	$ 162,707	$ 350,735	$ 513,442
Calculated	Classification - Income Tax	C-INCTAX	$ 114,501,551	$ 2,125,673,179	$ 115,147,649	$ 2,355,322,379
Calculated	Classification - Intangible Plant	C-INTPLANT	$ 12,568,129	$ 48,837,757	$ 18,219,562	$ 79,625,448
Calculated	Classification - Intangible Plant - CWIP	C-INTPLANTCWIP	$ 1,236,733	$ 4,805,749	$ 1,792,847	$ 7,835,330
Internal	Classification - Materials & Supplies - Production	C-MSPROD	$ -	$ 20,019,682	$ -	$ 20,019,682
Internal	Classification - Materials & Supplies - Transmission	C-MSTRAN	$ -	$ 4,234,334	$ -	$ 4,234,334
Internal	Classification - O&M Expense - Customer Accounts	C-OMCACCOUNT	$ (61,524,102)	$ -	$ -	$ (61,524,102)
Internal	Classification - O&M Expense - Conservation Improvement Program	C-OMCIP	$ -	$ -	$ (256,087,911)	$ (256,087,911)
Internal	Classification - O&M Expense - Customer Service and Information	C-OMCSERVICE	$ (2,049,342)	$ -	$ -	$ (2,049,342)
Calculated	Classification - O&M Expense - Distribution - Meters	C-OMDMETERS	$ 70,910,860	$ -	$ -	$ 70,910,860
Calculated	Classification - O&M Expense - Distribution Excluding Meters	C-OMDXMETERS	$ 142,168,036	$ 434,380,931	$ -	$ 576,548,967
Calculated	Classification - O&M Expense - Cash Working Capital	C-OMEXPCWC	$ (11,106,401)	$ (116,318,092)	$ (135,725,469)	$ (263,149,962)
Internal	Classification - O&M Expense - Fuel	C-OMFUEL	$ -	$ -	$ (109,355,211)	$ (109,355,211)
Internal	Classification - O&M Expense - Hydro Plant	C-OMHYDRO	$ -	$ (2,046,849)	$ (3,438,477)	$ (5,485,326)
Calculated	Classification - O&M Labor	C-OMLABOR	$ (12,023,322)	$ (46,783,208)	$ (17,423,728)	$ (76,230,258)
Calculated	Classification - O&M Labor - Administrative and General	C-OMLAG	$ (4,592,415)	$ (17,907,882)	$ (6,651,411)	$ (29,151,708)
Calculated	Classification - O&M Labor - Distribution	C-OMLDIST	$ (3,670,825)	$ (8,142,545)	$ -	$ (11,813,370)
Internal	Classification - O&M Labor - Hydro Plant	C-OMLHYDRO	$ -	$ (1,256,916)	$ (1,892,694)	$ (3,149,610)
Internal	Classification - O&M Labor - Solar Plant	C-OMLSOLAR	$ -	$ -	$ -	$ -
Internal	Classification - O&M Labor - Steam Plant	C-OMLSTEAM	$ -	$ (9,387,079)	$ (5,947,104)	$ (15,334,183)
Internal	Classification - O&M Labor - Wind Plant	C-OMLWIND	$ -	$ (542,096)	$ -	$ (542,096)
Calculated	Classification - O&M Labor Excluding Administrative and General	C-OMLXAG	$ (7,430,907)	$ (28,875,326)	$ (10,772,317)	$ (47,078,550)
Internal	Classification - O&M Expense - Other Power Supply	C-OMPOWER	$ -	$ (35,820,450)	$ -	$ (35,820,450)
External	Classification - O&M Expense - Purchased Power	C-OMPPOWER	$ -	$ (55,224,092)	$ (200,863,820)	$ (256,087,912)
Internal	Classification - O&M Expense - Sales	C-OMSALES	$ (109,355,211)	$ -	$ -	$ (109,355,211)
Internal	Classification - O&M Expense - Solar Plant	C-OMSOLAR	$ -	$ -	$ -	$ -
Internal	Classification - O&M Expense - Steam Plant	C-OMSTEAM	$ -	$ (18,181,946)	$ (17,638,504)	$ (35,820,450)
Internal	Classification - O&M Expense - Transmission	C-OMTRAN	$ -	$ (61,524,102)	$ -	$ (61,524,102)
Internal	Classification - O&M Expense - Wind Plant	C-OMWIND	$ -	$ (17,045,955)	$ -	$ (17,045,955)
Internal	Classification - Plant Held for Future Use	C-PHELD	$ -	$ -	$ -	$ -
Calculated	Classification - Property Tax	C-PROPTAX	$ (3,315,118)	$ (32,330,486)	$ (796,514)	$ (36,442,118)
Calculated	Classification - Average Rate Base	C-RATEBASE	$ 114,501,551	$ 2,125,673,179	$ 115,147,649	$ 2,355,322,379
Internal	Classification - Revenue - Disposition of Allowances	C-RDISPALL	$ -	$ -	$ 57,972	$ 57,972
Internal	Classification - Revenue - Dual Fuel	C-RDUALFUEL	$ -	$ -	$ 9,612,694	$ 9,612,694
Internal	Classification - Regulatory Expenses - MISO	C-REGEXPMISO	$ -	$ (6,468,216)	$ -	$ (6,468,216)
Internal	Classification - Revenue - Intersystem Sales	C-RISSALES	$ -	$ 2,105,918	$ 33,497,916	$ 35,603,834
Internal	Classification - Revenue - Production	C-RPROD	$ -	$ 4,238,152	$ 7,622,290	$ 11,860,442
Internal	Classification - Revenue - Resale	C-RRESALE	$ -	$ 29,110,381	$ 52,894,614	$ 82,004,995
External	Classification - Renewable Resources Rider	C-RRR	$ -	$ -	$ -	$ -
External	Classification - Revenue from Sales by Rate Class	C-RSALES	$ 48,952,872	$ 254,879,526	$ 401,837,365	$ 705,669,763
Internal	Classification - Prepaid Silver Bay Power	C-SBPC	$ -	$ -	$ 22,559,897	$ 22,559,897

Table 5 Classification Allocator Bases

Allocator Type	Classification Allocator Bases	Code	Customer	Demand	Energy	Total Company
Internal	Classification - Solar Plant	C-SOLAR	$ -	$ -	$ -	$ -
Internal	Classification - Solar Plant - CWIP	C-SOLARCWIP	$ -	$ -	$ -	$ -
Internal	Classification - Minnesota Solar Production Tax	C-SOLARTAX	$ -	$ -	$ (488)	$ (488)
External	Classification - Solar Renewable Resources Rider	C-SRRR	$ -	$ -	$ -	$ -
Calculated	Classification - State Income Taxes	C-STATEINCTAX	$ (614,850)	$ 16,557,775	$ (14,243,194)	$ 1,699,731
Calculated	Classification - State Taxes	C-STATETAX	$ 6,946,247	$ (158,843,255)	$ 145,587,504	$ (6,309,504)
Internal	Classification - Steam Plant	C-STEAM	$ -	$1,502,944,535	$ -	$ 1,502,944,535
Internal	Classification - Steam Plant - CWIP	C-STEAMCWIP	$ -	$ 6,911,363	$ -	$ 6,911,363
External	Classification - Transmission Cost Recovery Rider	C-TCR	$ -	$ -	$ -	$ -
Internal	Classification - Transmission Plant	C-TRAN	$ -	$ 820,030,517	$ -	$ 820,030,517
Internal	Classification - Transmission Plant - CWIP	C-TRANCWIP	$ -	$ 12,513,122	$ -	$ 12,513,122
Internal	Classification - UMWI	C-UMWI	$ -	$ 1,410,283	$ -	$ 1,410,283
Internal	Classification - Wind Plant	C-WIND	$ -	$ 800,397,179	$ -	$ 800,397,179
Internal	Classification - Wind Plant - CWIP	C-WINDCWIP	$ -	$ 317,904	$ -	$ 317,904
Internal	Classification - Minnesota Wind Production Tax	C-WINDTAX	$ -	$ -	$ (61,989)	$ (61,989)
Internal	Classification - WPPI	C-WPPI	$ -	$ (1,350,806)	$ -	$ (1,350,806)

Table 6 Classification Allocator Factors

Allocator Type	Classification Allocator Factors	Code	Customer	Demand	Energy	Total Company
Calculated	Classification - Accumulated Depreciation - Distribution Excluding Contra	C-ADDXCONTRA	0.3290998	0.6709002	0.0000000	1.0000000
Calculated	Classification - Adjusted Net Income Before Taxes	C-ADJNETINC	0.1368065	-0.6678821	1.5310756	1.0000000
Internal	Classification - Air Quality Emission Tax	C-AIRTAX	0.0000000	0.0000000	1.0000000	1.0000000
Internal	Classification - Asset Retirement Obligation	C-ARO	0.0000000	0.0000000	0.0000000	0.0000000
External	Classification - BEC4 Rider Revenue	C-BEC4	0.0000000	0.0000000	0.0000000	0.0000000
Internal	Classification - Cloquet Energy Center TG5	C-CEC	0.0000000	0.0000000	0.0000000	0.0000000
External	Classification - Conservation Improvement Program	C-CIP	0.0000000	0.0000000	0.0000000	0.0000000
Calculated	Classification - Distribution - CWIP Excluding Contra	C-DCWIPXCONTRA	0.2734583	0.7265417	0.0000000	1.0000000
Internal	Classification - Defer Rate Case Expense	C-DEFRCE	0.0000000	0.0000000	0.0000000	0.0000000
Calculated	Classification - Customer Deposits	C-DEPOSITS	0.4135361	0.5864639	0.0000000	1.0000000
Calculated	Classification - Distribution	C-DIST	0.3290998	0.6709002	0.0000000	1.0000000
Calculated	Classification - Distribution - CWIP	C-DISTCWIP	0.2734583	0.7265417	0.0000000	1.0000000
Internal	Classification - Distribution Other - Distribution Bulk Delivery	C-DODBD	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Distribution Other - Distribution Bulk Delivery Specific Assignment	C-DODBDSA	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Distribution Other - Distribution Primary Specific Assignment	C-DODPSA	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Distribution Other - Distribution Substations	C-DODSUB	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Distribution Other - Production	C-DOPROD	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Distribution Primary - Overhead Lines	C-DPOHL	0.3755000	0.6245000	0.0000000	1.0000000
Internal	Classification - Distribution Primary - Underground Lines	C-DPUGL	0.2420000	0.7580000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Leased Property	C-DSLEASED	1.0000000	0.0000000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Street Lighting	C-DSLIGHTING	1.0000000	0.0000000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Meters	C-DSMETERS	1.0000000	0.0000000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Overhead Lines	C-DSOHL	0.4944000	0.5056000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Overhead Services	C-DSOHS	0.5375000	0.4625000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Overhead Transformers	C-DSOHT	0.2634000	0.7366000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Underground Lines	C-DSUGL	0.1043000	0.8957000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Underground Services	C-DSUGS	0.2757000	0.7243000	0.0000000	1.0000000
Internal	Classification - Distribution Secondary - Underground Transformers	C-DSUGT	0.4938000	0.5062000	0.0000000	1.0000000
Calculated	Classification - Distribution Excluding Contra	C-DXCONTRA	0.3290998	0.6709002	0.0000000	1.0000000
Calculated	Classification - Electric Plant in Service	C-EPLANTIS	0.0609230	0.9165307	0.0225464	1.0000000
Calculated	Classification - Federal Taxes	C-FEDTAX	0.1731678	-1.4270904	2.2539225	1.0000000
Internal	Classification - Fuel Inventory	C-FUEL	0.0000000	0.0000000	1.0000000	1.0000000
Calculated	Classification - General Plant	C-GENPLANT	0.1578406	0.6133436	0.2288158	1.0000000
Calculated	Classification - General Plant - CWIP	C-GENPLANTCWIP	0.1578406	0.6133436	0.2288158	1.0000000
Internal	Classification - Hydro Plant	C-HYDRO	0.0000000	0.8716585	0.1283415	1.0000000
Internal	Classification - Hydro Plant - CWIP	C-HYDROCWIP	0.0000000	0.3168946	0.6831054	1.0000000
Calculated	Classification - Income Tax	C-INCTAX	0.0486140	0.9024978	0.0488883	1.0000000
Calculated	Classification - Intangible Plant	C-INTPLANT	0.1578406	0.6133436	0.2288158	1.0000000
Calculated	Classification - Intangible Plant - CWIP	C-INTPLANTCWIP	0.1578406	0.6133436	0.2288158	1.0000000
Internal	Classification - Materials & Supplies - Production	C-MSPROD	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Materials & Supplies - Transmission	C-MSTRAN	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - O&M Expense - Customer Accounts	C-OMCACCOUNT	1.0000000	0.0000000	0.0000000	1.0000000
Internal	Classification - O&M Expense - Conservation Improvement Program	C-OMCIP	0.0000000	0.0000000	1.0000000	1.0000000
Internal	Classification - O&M Expense - Customer Service and Information	C-OMCSERVICE	1.0000000	0.0000000	0.0000000	1.0000000
Calculated	Classification - O&M Expense - Distribution - Meters	C-OMDMETERS	1.0000000	0.0000000	0.0000000	1.0000000
Calculated	Classification - O&M Expense - Distribution Excluding Meters	C-OMDXMETERS	0.2465845	0.7534155	0.0000000	1.0000000
Calculated	Classification - O&M Expense - Cash Working Capital	C-OMEXPCWC	0.0422056	0.4420221	0.5157723	1.0000000
Internal	Classification - O&M Expense - Fuel	C-OMFUEL	0.0000000	0.0000000	1.0000000	1.0000000
Internal	Classification - O&M Expense - Hydro Plant	C-OMHYDRO	0.0000000	0.3731499	0.6268501	1.0000000
Calculated	Classification - O&M Labor	C-OMLABOR	0.1577237	0.6137092	0.2285671	1.0000000
Calculated	Classification - O&M Labor - Administrative and General	C-OMLAG	0.1575350	0.6142996	0.2281654	1.0000000
Calculated	Classification - O&M Labor - Distribution	C-OMLDIST	0.3107348	0.6892652	0.0000000	1.0000000
Internal	Classification - O&M Labor - Hydro Plant	C-OMLHYDRO	0.0000000	0.3990704	0.6009296	1.0000000
Internal	Classification - O&M Labor - Solar Plant	C-OMLSOLAR	0.0000000	0.0000000	0.0000000	0.0000000
Internal	Classification - O&M Labor - Steam Plant	C-OMLSTEAM	0.0000000	0.6121669	0.3878331	1.0000000
Internal	Classification - O&M Labor - Wind Plant	C-OMLWIND	0.0000000	1.0000000	0.0000000	1.0000000
Calculated	Classification - O&M Labor Excluding Administrative and General	C-OMLXAG	0.1578406	0.6133436	0.2288158	1.0000000
Internal	Classification - O&M Expense - Other Power Supply	C-OMPOWER	0.0000000	1.0000000	0.0000000	1.0000000
External	Classification - O&M Expense - Purchased Power	C-OMPPOWER	0.0000000	0.2156451	0.7843549	1.0000000
Internal	Classification - O&M Expense - Sales	C-OMSALES	1.0000000	0.0000000	0.0000000	1.0000000
Internal	Classification - O&M Expense - Solar Plant	C-OMSOLAR	0.0000000	0.0000000	0.0000000	0.0000000
Internal	Classification - O&M Expense - Steam Plant	C-OMSTEAM	0.0000000	0.5075856	0.4924144	1.0000000
Internal	Classification - O&M Expense - Transmission	C-OMTRAN	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - O&M Expense - Wind Plant	C-OMWIND	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Plant Held for Future Use	C-PHELD	0.0000000	0.0000000	0.0000000	0.0000000
Calculated	Classification - Property Tax	C-PROPTAX	0.0909694	0.8871736	0.0218570	1.0000000
Calculated	Classification - Average Rate Base	C-RATEBASE	0.0486140	0.9024978	0.0488883	1.0000000

Table 6 Classification Allocator Factors

Allocator Type	Classification Allocator Factors	Code	Customer	Demand	Energy	Total Company
Internal	Classification - Revenue - Disposition of Allowances	C-RDISPALL	0.0000000	0.0000000	1.0000000	1.0000000
Internal	Classification - Revenue - Dual Fuel	C-RDUALFUEL	0.0000000	0.0000000	1.0000000	1.0000000
Internal	Classification - Regulatory Expenses - MISO	C-REGEXPMISO	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Revenue - Intersystem Sales	C-RISSALES	0.0000000	0.0591486	0.9408514	1.0000000
Internal	Classification - Revenue - Production	C-RPROD	0.0000000	0.3573351	0.6426649	1.0000000
Internal	Classification - Revenue - Resale	C-RRESALE	0.0000000	0.3549830	0.6450170	1.0000000
External	Classification - Renewable Resources Rider	C-RRR	0.0000000	0.0000000	0.0000000	0.0000000
External	Classification - Revenue from Sales by Rate Class	C-RSALES	0.0693708	0.3611881	0.5694411	1.0000000
Internal	Classification - Prepaid Silver Bay Power	C-SBPC	0.0000000	0.0000000	1.0000000	1.0000000
Internal	Classification - Solar Plant	C-SOLAR	0.0000000	0.0000000	0.0000000	0.0000000
Internal	Classification - Solar Plant - CWIP	C-SOLARCWIP	0.0000000	0.0000000	0.0000000	0.0000000
Internal	Classification - Minnesota Solar Production Tax	C-SOLARTAX	0.0000000	0.0000000	1.0000000	1.0000000
External	Classification - Solar Renewable Resources Rider	C-SRRR	0.0000000	0.0000000	0.0000000	0.0000000
Calculated	Classification - State Income Taxes	C-STATEINCTAX	-0.3617337	9.7414070	-8.3796733	1.0000000
Calculated	Classification - State Taxes	C-STATETAX	-1.1009180	25.1752367	-23.0743187	1.0000000
Internal	Classification - Steam Plant	C-STEAM	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Steam Plant - CWIP	C-STEAMCWIP	0.0000000	1.0000000	0.0000000	1.0000000
External	Classification - Transmission Cost Recovery Rider	C-TCR	0.0000000	0.0000000	0.0000000	0.0000000
Internal	Classification - Transmission Plant	C-TRAN	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Transmission Plant - CWIP	C-TRANCWIP	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - UMWI	C-UMWI	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Wind Plant	C-WIND	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Wind Plant - CWIP	C-WINDCWIP	0.0000000	1.0000000	0.0000000	1.0000000
Internal	Classification - Minnesota Wind Production Tax	C-WINDTAX	0.0000000	0.0000000	1.0000000	1.0000000
Internal	Classification - WPPI	C-WPPI	0.0000000	1.0000000	0.0000000	1.0000000

Comparison of Minnesota Jurisdictional Factors

Allocation Code	Description	Final Ordered Projected Test Year 2017 Docket No. E015/GR-16-664	Actual 2018	Projected 2019	Projected Test Year 2020 Docket No. E015/GR-19-442
		(1)	(2)	(3)	(4)
Demand					
D01	Power Supply Production	84.36%	85.17%	86.65%	87.10%
D02	Power Supply Transmission	82.71%	83.54%	85.10%	85.57%
D03	Distribution Bulk Delivery	76.77%	80.32%	80.78%	80.63%
D04	Distribution Substations	100.00%	100.00%	100.00%	100.00%
D05	Primary Overhead Lines	100.00%	100.00%	100.00%	100.00%
D06	Secondary Overhead Lines	100.00%	100.00%	100.00%	100.00%
D07	Primary Underground Lines	100.00%	100.00%	100.00%	100.00%
D08	Secondary Underground Lines	100.00%	100.00%	100.00%	100.00%
D11	Overhead Line Transformers	100.00%	100.00%	100.00%	100.00%
D12	Underground Line Transformers	100.00%	100.00%	100.00%	100.00%
D14	Overhead Services	100.00%	100.00%	100.00%	100.00%
D15	Underground Services	100.00%	100.00%	100.00%	100.00%
Energy					
E01	Power Supply Production	84.31%	84.43%	86.34%	86.49%
CIPEXPE	Conservation Improvement Program Expense	100.00%	100.00%	100.00%	100.00%
CCRC	Conservation Cost Recover Charge	100.00%	100.00%	100.00%	100.00%
Customer					
C01	Primary Overhead Lines	100.00%	100.00%	100.00%	100.00%
C02	Primary Underground Lines	100.00%	100.00%	100.00%	100.00%
C03	Secondary Overhead Lines	100.00%	100.00%	100.00%	100.00%
C04	Secondary Underground Lines	100.00%	100.00%	100.00%	100.00%
C05	Overhead Line Transformers	100.00%	100.00%	100.00%	100.00%
C06	Underground Line Transformers	100.00%	100.00%	100.00%	100.00%
C07	Overhead Services	100.00%	100.00%	100.00%	100.00%
C08	Underground Services	100.00%	100.00%	100.00%	100.00%
C09	Leased Property	100.00%	100.00%	100.00%	100.00%
C11	Meters	98.56%	98.71%	98.71%	98.71%
C12	Customer Accounts	98.48%	99.59%	99.48%	99.44%
C13	Sales	94.55%	90.60%	88.29%	87.50%
C14	Customer Service	81.73%	71.89%	73.63%	73.60%
C15	Customer Accounts Credit Card Fees	100.00%	n/a	n/a	100.00%