CUB Exhibit # ______

State of Minnesota
Before the Public Utilities Commission

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota	: : : : :	Docket No. E-015/GR-21-335

DIRECT TESTIMONY

OF

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ON BEHALF OF
THE CITIZENS UTILITY BOARD OF MINNESOTA ("CUB")

(PUBLIC VERSION)

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I. INTRODUCTION

Q. Please state your name, business address and occupation.

A. My name is Ron Nelson. I am a Senior Director with Strategen Consulting. My business address is Suite 400, 2150 Allston Way, Berkeley, California 94704.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Citizens Utility Board of Minnesota ("CUB").

Q. Please describe your formal education and professional experience.

A. Currently, I am a Senior Director at Strategen Consulting. The Strategen team is nationally recognized for its thought leadership and deep expertise in regulatory innovation, performance-based regulation, rate design, renewable program development, grid modernization, and new grid technologies including distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. During my time at Strategen, I have worked with numerous consumer advocates, non-governmental organizations, utilities, and commissions on issues related to cost-of-service modeling, rate design, demand response, grid modernization, distributed energy resource valuation and integration, and performance-based regulation.

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led that office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics from Western Washington University where I minored in Mathematics.

Q. Have you testified in similar regulatory proceedings previously?

A. Yes. I have testified in Minnesota in approximately ten separate rate case proceedings on issues related to cost-of-service modeling, revenue apportionment, rate design, renewable program development, tariff analysis, fuel clause structure, multi-year rate plans, performance metrics, performance incentive mechanisms, decoupling, and the utility business model.

I have also testified in proceedings in Pennsylvania, Oklahoma, Illinois, New Hampshire, Vermont, Massachusetts, Utah, Michigan, and Ohio. The issues covered in these proceedings include marginal and embedded cost of service studies, formula rates, decoupling, performance-based regulation, DER interconnection, DER compensation, and smart inverter specifications.

I have also assisted with testimonies and regulatory analyses in Hawaii, Washington D.C., Maryland, Minnesota, Massachusetts, California, North Carolina, and the Federal Energy Regulatory Commission (“FERC”). The issues covered in these proceedings include electric vehicle rate design and infrastructure, cost-benefit analysis, community-based solar programs, rate design, integrated resource planning, energy storage integration, and DER interconnection.

A summary of my resume is attached as Schedule REN-1.

Q. Have you previously provided testimony before the Minnesota Public Utilities Commission ("Commission")?

A. Yes.

II. PURPOSE AND RECOMMENDATIONS

Q. What is the purpose of your testimony?

A. I am testifying on the reasonableness of certain elements of the Company's rate case application.

Q. How is your testimony organized?

A. My testimony is organized into the following sections:

- UIPlanner procurement process
- CCOSS and production demand allocation
- Large Power risk and its impact on Company decision-making
- Revenue apportionment

Q. What are your recommendations regarding the Company's application?

A. I recommend that the Commission:

1. Deny the Company's $1.9 million cost recovery request for the UIPlanner investment.

2. Continue to use the P&A approach for production demand allocation.

3. Consider Large Power customer risk factors that result in incremental cost incurrence and cost shifting in the Company's CCOSS when apportioning revenue to customer classes.

4. Replicate its approach from the order on interim rates and assign half of the total percentage rate increase to the residential class with equal and commensurate increases for the other customer classes – including the Large Power customer class.

III. UIPLANNER PROCUREMENT PROCESS WAS UNREASONABLE

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

A. In this section, I discuss the imprudent procurement process used for the UIPlanner and recommend a disallowance to ensure ratepayers are not burdened by Minnesota Power's unreasonable expense. To demonstrate the degree to which Minnesota Power deviated from best practices, I discuss best practices used by other utilities, including the development of a business case.

Q. What is the UIPlanner?

A. UIPlanner is a tool that Minnesota Power selected for moving to a new Class Cost-of-Service Study (CCOSS) model, claiming that it was "the best option for improving CCOSS modeling efficiency, accuracy, and transparency."[1] The total project cost to implement UIPlanner was $1.9 million.[2]

Q. What is your concern related to the UIPlanner?

A. I am concerned that Minnesota Power did not utilize a prudent procurement process for obtaining UIPlanner, and that the $1.9 million spent on the tool is therefore unreasonable. Specifically, I am concerned that the Company did not develop a business case for the proposed investment, nor did it adequately compare alternatives.

Q. What is a business case?

A. A business case is a form of analysis utilized by utilities throughout the country to evaluate expenditures and investments. It is typically an internal process, although business cases can be used in regulatory proceedings to demonstrate that a reasonable and prudent decision-making approach was utilized for a given investment. Business cases are similar to traditional cost-benefit analyses.[3] However, business cases tend to be more flexible and geared towards defining

[1] Shimmin Direct Testimony at 5.
[2] Shimmin Direct Testimony at 10.
[3] Woolf, Tim, Ben Havumaki, Divita Bhandari, Melissa Whited, & Lisa Schwartz. "Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations." synapse-energy.com. February 2021. https://www.synapse-energy.com/sites/default/files/GMLC-Grid-Mod-BCA-2021-02-02-18-094.pdf.

benefits and costs that are harder to quantify and monetize.[4] A general roadmap for determining which expenditures and investments will serve the best interests of the utility and customers follows three steps: (1) identifying objectives, (2) evaluating utility resources, stakeholders, and organization, and (3) defining the business case.[5]

Q. What are the components of a business case?

A. There are several components of a business case. Once a utility has identified its objectives and conducted an internal evaluation, a business case generally incorporates three key elements: (1) benefits, (2) costs, and (3) comparison to alternatives. Other components of a business case can include some combination of the following: (1) operational and system benefits, (2) customer benefits, (3) cost to savings comparison, 4) system integration, (5) financial impacts, and (6) alternative options and approaches.

Q. What general process do utilities follow when developing a business case?

A. There is no standardized process for developing and conducting a business case. Utilities across different states follow different procedures. However, there are several examples of business cases that offer insight on the business case

[4] Business cases vary from one another, emphasizing different aspects of the expenditure or investment. Some business cases focus more on monetization of costs and benefits in the same way cost-benefit analyses do but allow for the ability to consider non-monetized considerations. Business cases can also diverge from traditional cost-benefit analyses and evaluate qualitative elements of expenditures and investments.
5 FTI Consulting. "A Roadmap for Developing the Public Utility of the Future," n.d. http://documents.jdsupra.com/261b64d9-e9a0-42b8-a376-e8a7e3f405f4.pdf.

development process and the important role business cases play in utility investment and expenditure decisions.

In New Hampshire, unplanned projects over $50,000 require a business case.[6] The business case must include recommendations, objectives, background, alternatives/options, financial assessment, risk assessment/qualitative evaluation, and implementation/action plan.

Another example is Avista Utilities' 2015 General Rate Case: the utility conducted a business case to justify several proposals.[7] The utility included a description of its general capital budgeting process as support for its capital spending and stated that its capital budgeting process started with individual business cases. These business cases must include the following: project description, project alternatives, cost summary, business risk, financial assessment, strategic assessment, justification for the project, milestones, and key performance indicators.[8] The utility also provided a business case to justify its attrition adjustment for pro forma plant additions.

Additionally, Avista justified its proposal for deploying advanced metering infrastructure (AMI) through its Washington service territory using a business case. The business case included estimated net present benefits of AMI.

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[6] Final Report on A Management and Operations Audit of The Customer Service and Accounting Functions of Liberty Utilities. Docket No. DG 20-105

[7] Washington Utilities and Transportation Commission Dockets UE-150204 and UG-150205. Final Order Rejecting Tariff Filing, Accepting Partial Settlement Stipulation, Authorizing Tariff Filings.

[8] Ibid.

However, it did not offer a comprehensive analysis of the costs and did not present any alternative approaches. The Commission rejected the proposal, determining that the proposal was not ready for a decision as several components of AMI deployment had not been considered by the business case at the time of the proposal.

Q. Did Minnesota Power conduct a business case for its UIPlanner investment?

A. No, it did not. The Company did not substantively compare the UIPlanner to other alternatives, nor did it conduct a formal cost-benefit analysis.

Q. Does Minnesota Power claim that it considered alternatives?

A. Yes, the Company claims that it considered alternatives by "commissioning a cross-functional internal team" that "worked on evaluating different methods for developing a CCOSS and process improvements" and "conclude[d] that selecting the UI Regulatory module to build the CCOSS model was a 'best practice.'"[9] The Company "considered" three alternatives:[10]

1. Continuing to use the prior Excel-based system, which the Company rejected for being insufficiently robust, flexible or transparent to accommodate the increasing amount of data and the different queries

[9] DOC IR 0705.2 in E015/GR-19-442.
[10] Shimmin Direct Testimony at 9-10.

required. It deemed the same issues would be inherent in other Excel-base models as well.

2. Developing a new CCOSS system in-house, which the Company rejected because of the required modeling complexity to develop, and lack of internal expertise or resources for developing such a system.
3. Acquiring another CCOSS modeling system, which the Company chose based on an informal poll and follow-up interviews amongst EEI conference attendees who reported satisfaction with UIPlanner.

Apparently, the Company found no "feasible alternatives" to UIPlanner nor "comparable product designed specifically for this purpose."[11]

Q. Do you find the Company's consideration of alternatives to be reasonable?

A. No. The Company does not provide an explanation of its process for seeking feasible alternatives or comparable products. There is no evidence that the Company conducted a comprehensive search or even contacted a single alternative provider for functionality or cost estimates. When asked whether it considered hiring an internal laborer to build an Excel-based CCOSS, the Company simply reiterated its previous statements about the complexity of such a project and its lack of expertise or resources.[12] However, it appears that the

[11] Shimmin Direct Testimony at 10.
[12] CUB IR 0043 in E015/GR-19-442.

Company did not hesitate to dedicate significant financial resources to the UIPlanner implementation.

It is also unclear how the Company could determine that no other CCOSS met the Company's requirements and criteria, when Minnesota Power did not correspond with any other possible CCOSS vendors,[13] nor did it perform any sort of RFP for acquiring a new CCOSS model.[14]

The Company's decision to conduct no quantitative analysis on alternatives to the UIPlanner[15] appears to contradict a company requirement in the Company's Purchasing Manual, which states that, "[a]s a regulated utility, Minnesota Power is required to obtain competitive quotations on all purchases of materials and services. All business units do this as a best practice." In fact, there must be a minimum of two to three quotes for requests over $10,000.[16] No such competitive quotations were sought for the $1.9 million UIPlanner procurement.

For all the above reasons, I find the Company's consideration of alternatives to be unreasonable and its conclusion that there were no suitable alternatives to be unsubstantiated.

Q. Does Minnesota Power claim that it could not conduct a cost-benefit analysis?

[13] DOC IR 0705.7 in E015/GR-19-442.
[14] DOC IR 0705.8 in E015/GR-19-442.
[15] CUB IR 0044 in E015/GR-19-442.
[16] Purchasing Manual. Allete, Inc. Revised October 19, 2020. Included as CUB IR 0003.01 Attach PUB. At 14.

A. Yes, although the Company claimed that its cross-functional team evaluated the "costs and benefits of these different methods,"[17] the Company also acknowledges that it did not perform a formal cost-benefit analysis of the new CCOSS model, claiming that many of the benefits of the new model cannot be quantified.[18]

Q. Do you agree that the Company could not conduct a cost-benefit analysis?

A. No. I disagree with the Company that the stated benefits are unquantifiable. Utilities are faced with procurements similar to, if not exactly like, this all the time, as the above Washington and New Hampshire examples attest. Business cases, or another process, are used to guide decisions that are difficult to quantify, but few are impossible to quantify from a business perspective. For example, the Company claimed that it would take significant employee resources to create an Excel-based model, but they don't say how much – is it more than $2 million? The Company also claimed that the software should create many benefits but failed to quantify any of them.[19]

Q. Does the UIPlanner cost impact the importance of conducting a business case?

A. Yes. In a November, 5, 2018 Steering Committee meeting, the Company shared initial estimates that the project costs would include a $250,000 regulatory

[17] DOC IR 0705.2 in E015/GR-19-442.
[18] DOC IR 0705.4 in E015/GR-19-442.
[19] Shimmin Direct Testimony at 6-9.

module purchase, $300,000 implementation costs plus travel, and $50,000 maintenance per year.[20] At a subsequent Steering Committee meeting just 10 days later, the implementation cost estimate had risen to $750,000.[21] The increase in the implementation budget from $300,000 to $750,000 in just 10 days is unexplained and the internal approval process undocumented. Contradicting these initial estimates, the Company's application in this rate case claims that UIPlanner was initially estimated at $2.4 million,[22] as if to suggest that the ultimate $1.9 million project cost represents some sort of savings. However, it is unclear where or when the supposed $2.4 million initial estimate was publicized. The significant uncertainty around the initial UIPlanner cost estimate and the dramatic increase between the initial Steering Committee estimates and the final $1.9 million cost suggest the project was imprudently managed. The Company should require significant review for a project budget increase of this magnitude. No explanation has been provided as to whether such a review occurred and, if not, why not. The escalating and opaque project pricing process represents yet another reason why the UIPlanner procurement was unreasonable.

Q. What are your recommendations regarding the UIPlanner investment?

A. Given the Company's failure to create a transparent business case, or other similar information, to solicit alternatives to the UIPlanner, and to explain the

[20] CUB IR 0039.02 Attach in E015/GR-19-442.
[21] CUB IR 0039.03 Attach in E015/GR-19-442.
[22] Shimmin Direct Testimony at 10.

significant budget increases, and given its apparent violation of its own internal procurement processes, I recommend that the Commission reject MP's $1.9 million UIPlanner investment.

IV. CCOSS PRODUCTION DEMAND ALLOCATION

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

A. In this section, I provide background information about CCOSSs, before describing and critiquing one of the Company's CCOSS approaches: production-demand allocation.

1. The Influence of Economic Incentives on Cost-of-Service Studies

Q. Before you discuss the details of the CCOSS, please explain how economic incentives may influence cost studies.

A. When evaluating cost studies, and the rate designs they inform, decision-makers should consider how the economic incentives of for-profit, investor-owned utilities ("IOUs") can impact assumptions within utility-sponsored cost-of-service studies.

In a perfect world, corporate profit maximization would align with the objectives of those corporations' customers. However, that is not the case for IOUs. For this reason, it is important for decision-makers to understand how IOUs' economic incentives may not align with public policy goals and ratepayer interests, in order to evaluate cost modeling and rate design proposals more effectively.

Q. Please provide examples of where a utility's economic incentives may not align with policy goals or ratepayer interests.

A. There are two interrelated issues that can impact the utilities' perspective when conducting cost studies.

First, the price elasticity of demand for electricity is the sensitivity, or elasticity, associated with the quantity of electricity demanded given a change in the price of electricity. Specifically, the elasticity of demand measures how much a consumer changes her consumption of electricity given a change in price. Because large customers have more elastic demand than residents, large customers will decrease their demand for electricity more than residents due to an equivalent price change, all else constant. This relationship means that utilities can benefit financially from shifting costs from large to residential customers. This presents the utility with an incentive to shift subjective cost allocations (and there are many in cost studies) to classes with inelastic demand by increasing their rates.[23]

Second, third-party services act as substitutes for utility services. Traditionally, utilities have had few competitors (e.g. other utilities or natural gas

[23] *See generally* James C. Bonbright, Albert L. Danielsen, & David Kamerschen, *Principles of Public Utility Rates* (2d ed. 1988).

as a fuel alternative) and have never faced competition on the distribution system. Currently, competitors are providing services that compete with those provided by the utility, such as solar plus storage. The presence of this competition impacts utility incentives in many ways, but generally utilities may take actions to make their services more cost-competitive in an unfair fashion. The utility has a particularly significant incentive to retain its large customers, so the competition between third parties and utilities provides an additional incentive for utilities to shift costs off of large customers and onto smaller ones (to keep large customer rates low and less susceptible to third parties undercutting utility rates).

Q. How do the economic incentives of a utility impact cost studies in practice?

A. The utility perspective is largely informed by its economic incentives. For this reason, when subjective determinations are made within a cost-of-service study or when designing rates, utilities are likely to make assumptions that benefit their bottom line —as would any for-profit business in a similar position. This is especially problematic in cost studies and rate design because there are numerous subjective assumptions made to develop both. I discuss the subjective decision made by Minnesota Power in its allocation of production demand below.

Q. Why are you highlighting these perverse economic incentives for decision-makers?

A. My goal is to ensure that decision-makers understand the economic incentives that influence the perspectives a utility shares in regulatory proceedings and when it constructs cost-of-service and other rate related models. My goal is not, however, to denounce the utility, which is simply responding to the regulatory framework and the resulting economic incentives in which the Company operates. For this reason, creating a more effective regulatory framework is fundamental to better aligning the economic incentives of a utility with the needs of its customers.

2. *Traditional CCOSS Methodology*

Q. What is the purpose of a CCOSS?

A. The purpose of a CCOSS is to decipher, with as much detail and accuracy as possible, which customer class caused the utility's various embedded costs associated with providing service.

Q. How is a CCOSS performed?

A. A CCOSS has three steps. First, costs are functionalized into various categories. Second, costs are classified as energy, demand/capacity, or customer. Lastly, the costs are allocated to the various customer classes using allocators related to energy, demand/capacity, or customer characteristics.

Q. How are costs functionalized?

A. Public utilities are required to maintain records in accordance with the Uniform System of Accounts as designated by the Federal Energy Regulatory Commission ("FERC"). These accounts assign costs by various functions, such as generation, transmission, and distribution. The purpose of functionalizing costs is to aid in determining which customers are jointly or solely responsible for various costs.

Q. How are costs then classified?

A. Cost causation is used to determine whether each cost is classified as a commodity, demand, or customer cost. Energy costs relate to a customer class's energy usage, measured in kilowatt-hours ("kWh"). Capacity costs relate to a customer class's contribution to peak demand within the system, measured in kilowatts ("kW"). Finally, customer costs are those required to provide service to customers, regardless of whether the customers consume electricity.

Q. How are costs allocated once they have been classified?

A. Costs are allocated to customer classes based on each class's contribution to each classified cost. For example, if the company spends the same amount of time and money on each customer location, regardless of class, then it is appropriate to allocate that cost based on the number of customer locations. This result stems from the fact that the number of customer locations, rather than a customer's electricity consumption, causes costs to be incurred.

3. *Minnesota Power's Production-Demand Allocation*

Q. What costs do you discuss in this section and why are they important?

A. I discuss the Company's general treatment of production plant costs. The accuracy and equitable allocation of these costs is important because production plant accounts for a significant amount of Minnesota Power's rate base.

Q. How does Minnesota Power classify production plant?

A. Minnesota Power classifies all production plant, except for hydro, as 100% demand.

Q. What justification does MP provide for this classification approach?

A. MP explains that classifying production plant as demand is consistent with prior retail rate cases and in some cases with the NARUC manual.[24]

Q. What are the implications of classifying most production costs as demand related?

A. Traditionally, classifying production costs as demand-related suggests collecting those costs through a demand charge for classes that have that rate determinant. Conversely, classification as energy-related suggests collection through a volumetric rate. As technology advances and the power system requires more

[24] Shimmin Direct Testimony Schedule 1 at 8, 10, 11.

flexibility, classifying production costs as energy-related may be more efficient, as long as rate design also changes to deliver the proper price signals.

Q. How does Minnesota Power allocate demand-related production plant?

A. The Company proposes to replace its use of the Peak & Average (P&A) approach – a methodology recommended to the Company in 1980 and "used, approved, or considered" in the last three completed retail rate cases[25] - with the 4CP Average and Excess (A&E) approach.

Q. Do you agree with the Company's proposed new production demand allocation methodology?

A. No, I do not. The Company makes several claims as to why the P&A method is inappropriate and the 4CP A&E more appropriate; I will address each below.

Q. Do you agree with the Company that 4CP A&E results in fairer and more equitable cost allocation?

A. I disagree for several reasons. First, MP made up its own, deeply flawed method for evaluating fairness and equity: an "Index of Production Demand Revenue Requirements per kW."[26] The Company determined each class's production demand revenue requirement, then divided the production demand revenue

[25] Shimmin Direct Testimony at 17.
[26] Shimmin Direct Testimony at 32, Table 5.

requirement by each class's contribution to coincident peak,[27] resulting in a dollar-per-kW value that it ultimately compared, or "indexed", to the overall $/kW Minnesota jurisdictional system average.[28] The Company did this calculation for several different allocation approaches and compared each approach to the jurisdictional system average score.[29] Using this index, the Company claims that a "a much fairer and more equitable cost allocation"[30] occurs when the residential class cost index is closer to system average.

My concern with the Company's index is that it resulted in the Company claiming that more fair and equitable cost allocation occurs when each class's production demand revenue requirement is most closely proportional to its contribution to system peak coincident demand. Essentially, the Company wants a method that brings each class as close to a single CP allocation as possible. It is unclear why an index based on each class's contribution to single coincident peak would help the Company determine the fairness of its cost allocation approach. Dividing by class contribution to coincident peak places undue weight on the single coincident peak, when MP has stated that 1) cost causation is more accurately represented by a measure of energy and demand[31] and 2) it's

[27] Class contribution to coincident system peak refers to the combined demand of a customer class during the annual peak demand of the Minnesota Power system.
[28] Minnesota jurisdictional system average refers to the total Minnesota production demand revenue requirement divided by the total coincident peak demand ($/kW). *See* Shimmin Direct Testimony at 23.
[29] Shimmin Direct Testimony at 32, Table 5
[30] Shimmin Direct Testimony at 23.
[31] Shimmin Direct Testimony at 24.

important to consider four peaks.[32] As the power system integrates additional renewable energy, the focus on a single peak becomes even more tenuous, because balancing supply and demand (i.e., flexibility) throughout the year will require a variety of grid services and resources.

Second, MP provides no justification as to why its subjective index is a credible way to determine whether a cost allocation approach is "fair and equitable."[33] Considerations of equity in cost allocation should take into account issues like residential energy burden within the Company's service territory,[34] rather than proportionality to class coincident peak contribution. Additionally, the excess risk created by the Large Power class and the resulting cost shifting, as discussed in other sections of my testimony, should be considered when evaluating equity, and the Company's index does no such thing.

Q. Do you agree with the Company that P&A has an "inherent double-counting flaw?"

A. No. The Company claims that the P&A average calculation double-counts the demand portion of the peak demand because average demand represents the energy-related portion of the composite allocator but is also a component of peak

[32] Shimmin Direct Testimony at 25.
[33] Shimmin Direct Testimony at 23.
[34] The Public Service Commission of Wisconsin recently announced that it would require investor-owned utilities with at least 15,000 customers to provide a detailed household economic burden index analysis – data which will help "make sure that critical utility service is provided not only safely and reliably, but equitably and affordably, as well." https://www.wpr.org/sites/default/files/pdf_download_4.pdf.

demand.[35] This claim is false. Average demand and peak demand are two distinct metrics. They may be derived from the same dataset (hourly demand) but there is certainly no average demand embedded into and double-counted within the peak demand factor, as MP suggests. Average demand provides a measure of production fuel efficiency and other energy-related attributes, while measures of peak demand represent capacity attributes. Average demand is not a component of peak demand.

On the other hand, excess demand, as measured in the Company's proposed 4CP A&E alternative, is not a measure of any specific production attribute. Instead, it is a derivative of two attributes with no clear connection to a grid services.

Q. Do you agree with the Company that 4CP A&E "would provide better cost signals needed for utility of the future initiatives?"

A. No. The Company claims that "capturing or accounting for each class's unique load characteristics" and the resulting "more accurate cost allocation method would be preferred when considering peak shifting or peak reduction programs which support lower overall system costs."[36] The Company's claims are misleading. Using a different production allocator will not change how MP collects its costs through rates, given that it continues to classify almost all

[35] Shimmin Direct Testimony at 19-20.
[36] Shimmin Direct Testimony at 27.

production as demand-related. Unless directly translated into rate design, changing a production allocator does not send a more granular price signal to customers.

Furthermore, the utility acts as a load aggregator, not a load disaggregator. This is because aggregated load is more cost-effective to serve because of higher load diversity. Load diversity is a key component of cost allocation. The closer a power system facility is to a customer, the lower the load diversity, and hence the more important individual and class load are for cost allocation. For example, a line transformer could have anywhere from 2-8 residential customers on it. The aggregated load of that set of customers necessarily determines the capacity requirement of the line transformer. As the grid moves away from the customer premises, individual loads are less related to cost causation because load become more aggregated and diverse. For example, at the substation, individual and class specific loads have little to do with cost causation and should not be used to allocate these costs. Instead, substations are often treated like the transmission system and allocated based on peaks related to system load – not on a class's unique load characteristics. To summarize, anything from the substation and above should not reflect a class's unique load characteristics.[37]

[37] The exception, of course, would be directly assigned costs.

Q. Do you agree with the Company that the 4CP A&E approach better reflects cost causation?

A. No. The Company claims that the 4CP A&E approach better reflects cost causation because it "recognizes customers benefit from both demand and energy production" – as opposed to just demand – "from the Company's fixed generation assets and are allocated costs accordingly."[38] Specifically, the Company touts that its approach accounts for energy-related usage "by capturing each class's contribution to the system average demand."[39] However, the former P&A method also captured each class's contribution to the system average demand and, in that respect, 4CP A&E is no better than the P&A method. It is also concerning that the 4CP A&E method treats all production the same.

Q. Why is it concerning that the 4CP A&E method treats all production the same?

A. The 4CP A&E method lacks specificity because it relies on gross system indicators, such as system load factor, to determine energy and demand components. Because this high-level approach allocates costs based solely on customer loads, it fails to reflect changes in the utility's generation resource mix, when production plant allocation should instead reflect the purpose for which

[38] Shimmin Direct Testimony at 24.
[39] Shimmin Direct Testimony at 25-26.

these fossil generators were built. Such broad treatment of production resources ignores cost-causation.

Investment in different resources can, in fact, demonstrate specific needs on the power system that indicate whether those costs are energy- or capacity-related (e.g. peakers are generally built to meet capacity reliability need, while baseload is built to meet energy need), but 4CP A&E would allocate plant in the same way whether it was made up of peaker or baseload resources.

Q. What do you recommend regarding production demand allocation in this case?

A. I recommend that the Company continue to use the P&A approach.

V. LARGE POWER RISK AND ITS IMPACTS ON MP'S APPLICATION

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

A. I begin by discussing the significant business risk associated with the Large Power customer class. I then explain how that risk deeply influences the Company's decision-making – in this case, to the benefit of the LP customer class and to the detriment of other classes. I provide several examples of biased decision-making and recommend alternative approaches for the Commission to consider.

1. Large Power Risk

Q. Describe the risk associated with the Company's Large Power customers.

A. As stated in its initial filing, Minnesota Power faces "higher business risk" due to having "an extremely high concentration of industrial customers, operating in only two industries, each with the independent ability to create large swings in utility revenues."[40] The description indicates that business risk results from two distinct characteristics of the Company's Large Power customer class: 1) the Company's sales concentration in large industrial customers and 2) the nature of those customers' specific industries (and the fact that the Large Power customer class operates in only two industries). I discuss both risk factors below.

Q. Describe the Company's customer concentration risk.

A. Minnesota Power obtains a substantial portion of its sales from an extremely small number of customers operating in an even smaller number of industries – making the Company highly dependent on those customers' demand. Specifically, nine large industrial customers represent more than 60 percent of the Company's total retail kWh energy sales and approximately 50 percent of the Company's peak demand.[41] Furthermore, over half of 2020 retail kWh electric sales came from just two companies in the mining sector.[42]

The Company directly quoted industry literature on customer concentration risk and concluded that "a company that has a high degree of

[40] Bulkley Direct Testimony at 39.
[41] Bulkley Direct Testimony at 41.
[42] Bulkley Direct Testimony at 39.

customer concentration will be inherently riskier than a company that derived income from a larger customer base."[43] The customer concentration risk of the Large Power class, therefore, distinguishes Minnesota Power from a utility with a high residential sales volume, given that the Company's sales concentration is spread across only a handful of individual customers – each of which significantly affects the Company's business – rather than across thousands of customers who would not individually affect the Company's financial position.

The Company's outsized sales concentration in such a small number of Large Power customers leaves it highly vulnerable to volatility amongst any of those customer accounts. In turn, the inherent riskiness of those customers' industries further compounds the Large Power business risk.

Q. Describe the Company's Large Power customer industry risk.

A. Minnesota Power is highly vulnerable to the instability of its Large Power customers' two main industries, as confirmed in the Company's testimony: "The volatility in the mining industry coupled with the decline in production at the pulp and paper mills…will have a direct effect on the electric sales of Minnesota Power."[44] Within the mining industry, taconite processing – which constitutes over half of Minnesota Power's retail kWh sales – "is highly dependent on

[43] Bulkley Direct Testimony at 40.
[44] Bulkley Direct Testimony at 43.

economic conditions and the business cycle."[45] The Company acknowledges that this dependency directly impacts its bottom line, noting that "fluctuations in the business cycle could have a large impact on Minnesota Power's retail electric sales."[46] Indeed, Witness Bulkley confirms that "energy sales to industrial customers have been significantly affected by the business cycle,"[47] sharing multiple examples of sales downturns over the past decade or so. The Company also asserts that it cannot make up for lost retail sales through the energy market.[48]

Q. Does the Company's proposed sales true-up mechanism indicate its high degree of customer concentration and industry risk?

A. Yes. The Company proposed a mechanism that would allow it to "modulate the impacts of the most significant swings in industrial customer volatility"[49] by recovering lost revenue if sales fall by over $10 million. However, the Company notes that even that mechanism "would not eliminate all of the customer concentration risk."[50] Clearly, the Company feels the need to protect itself from its very high exposure to a small set of unstable industries and spends considerable time and resources developing approaches to do so.

[45] Bulkley Direct Testimony at 40.
[46] Bulkley Direct Testimony at 42.
[47] Bulkley Direct Testimony at 42.
[48] Bulkley Direct Testimony at 46.
[49] Bulkley Direct Testimony at 47.
[50] Bulkley Direct Testimony at 47-48.

As will be discussed in the below section, the costs of developing regulatory mechanisms, such as MP's sales true-up mechanism, are directly caused by Large Power customers and in many cases should be directly assigned to these customers – but they are not. Instead, costs directly caused by Large Power customers are shared across all customer classes including the residential class.

2. Large Power Risk Influences Minnesota Power's Decision-Making

Q. How does the Company's vulnerability to Large Power customer risk affect its decision-making?

A. The Company's reliance on sales revenue from a small number of Large Power customers in just two volatile industries affects its business decisions, cost structure, and cost collection proposals in this rate case. Minnesota Power's risky position is so unique and extreme that it fundamentally impacts most aspects of the Company's business. Such dependence on LP customer success means that serving those customers directly impacts the utility's business model and its underlying cost of service to service all its customers.

The riskiness of the Large Power class drives significant Company costs, as I will discuss below. Because Minnesota Power relies heavily on revenue from its Large Power customers, it is incentivized to socialize costs that are largely, or solely, caused by the Large Power class to maintain low rates for them, and to generally make decisions in favor of the LP class, which often occur at the expense of others, such as residential customers.[51]

Q. Can you provide examples of Company decision-making that prioritizes Large Power customers?

A. Yes, I can. Below, I detail the following examples:

- Nemadji Trail Energy Center (NTEC)
- Customer-class return on equity (ROE)
- Allocation of regulatory costs
- Allocation of production demand costs

Q. Does the Company's experience with NTEC demonstrate how its high degree of Large Power risk can cause costs directly related to its Large Power customers but shared across all customers?

A. Yes. On July 28, 2017, the Company filed a petition for approval of several supply-side generation projects, including NTEC.[52] The Company would have a 48 percent capacity share of the 535 MW natural gas combined-cycle facility in

[51] Note that I am speaking to an economic incentive. This means that the Company's profits benefit from certain decisions and so managers within the Company "perform well" when these decisions are made. I am not suggesting that Minnesota Power's employees are making malicious, or even intentional, decisions to harm other ratepayers. The point is that managers and decision makers within Minnesota Power have a stronger economic incentive to make decisions to protect and improve the financial circumstances of Large Power customers when compared to other customer classes, given the risks discussed in this section. This strong economic incentive will likely result in biased decisions and cost shifting within the Company.

[52] Minnesota Power Petition for Approval of the Energy*Forward* Resource Package. Docket No. E015/M/AI-17-568.

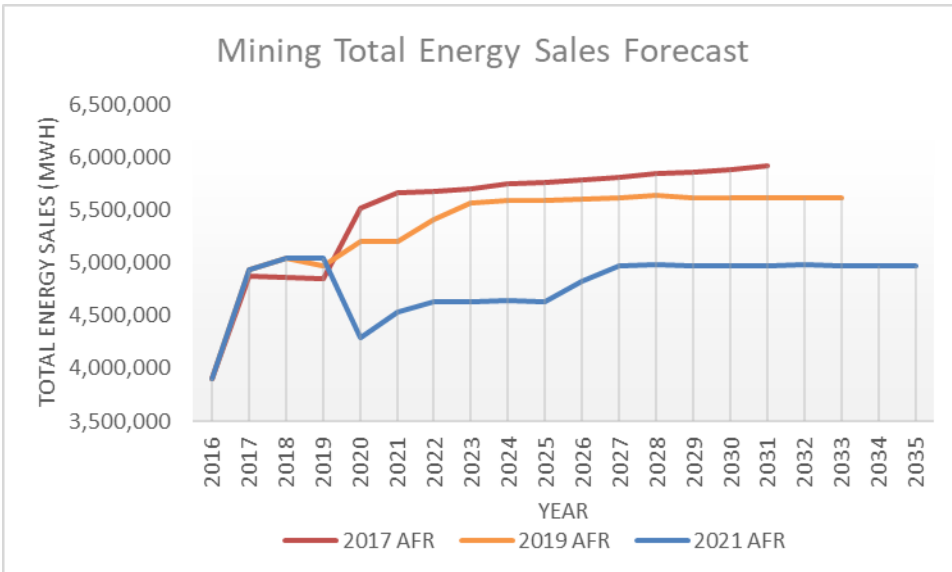
Wisconsin. On January 24, 2019, the Commission approved a capacity dedication agreement and an affiliated interest agreement for the plant.[53] However, in September 2021, Minnesota Power's parent company Allete Inc. announced that 30 percent of the capacity share of NTEC was sold to Basin Electric Power Cooperative.[54] This sale reflects the significant decline of forecasted total energy sales across customer classes, and specifically in the large power customer class. This forecast decline can be attributed to several factors including rapidly changing market conditions for large power customers as well as the Company over-forecasting demand for its large power customer class. For example, in the Company's 2021 Integrated Resource Plan (IRP), the base case load forecast assumes PolyMet NorthMet mine will become operational in 2025.[55] However, the PolyMet NorthMet Project has been met with delays and heavy protests, leaving the mine unlikely to become operational in 2025.[56]

The chart below shows the significant decline in energy sales forecast for the mining and metal and paper and wood products in the 2021 Annual Forecast Report (AFR)[57] compared to the 2017 AFR (the forecast most similar to the

[53] Minnesota Public Utilities Commission Order Approving Affiliated-Interest Agreements with Conditions Docket No. E015/M/AI-17-568.
[54] "Allete Announces Third Partner in Nemadji Trail Energy Center Project." ALLETE, Inc., September 28,2021. https://investor.allete.com/news-releases/news-release-details/allete-announces-third-partner-nemadji-trail-energy-center.
[55] Minnesota Power 2021 Integrated Resource Plan. pg. 19.
[56] "Minnesota Supreme Court Orders New Hearing in Polymet Copper Mine Dispute." MINING.COM, April, 28, 2021. https://www.mining.com/mining0court0rules-against-polymet-copper-nickel-project/.
[57] Minnesota Power's 2021 Annual Electric Utility Forecast Report. Docket No.: E-999/PR-21-11 https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={101B5E7A-0000-CB1C-9B90-3D131DA9FC6B}&documentTitle=20216-175588-01

forecast used in the Energy*Forward* Resource Package filing that the Company included in its petition for approval to purchase electricity from NTEC)[58] and the 2019 AFR (the forecast for the year the capacity dedication agreement was approved by the Commission).[59]

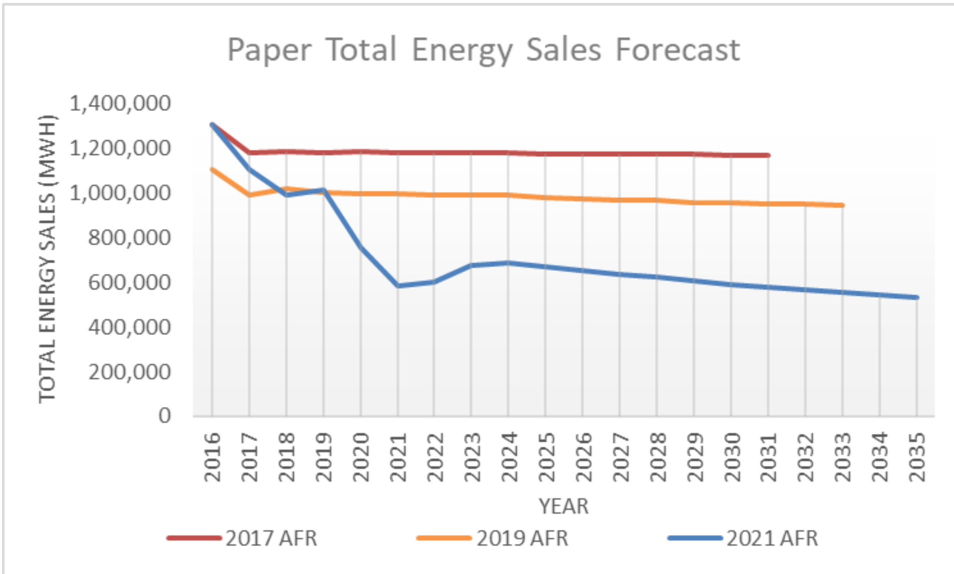
Graph 1. Mining Total Energy Sales Forecast



[58] Minnesota Power's 2017 Annual Electric Utility Forecast Report. Docket No.: E-999/P -17-11 https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={800EF15D-0000-C01F-B96A-09EEC61BA015}&documentTitle=20178-134795-01

[59] Minnesota Power's 2019 Annual Electric Utility Forecast Report. Docket No.: E-999/PR-19-11 https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={40FF006C-0000-C415-A4B2-EC19E4FB0FD6}&documentTitle=20197-154438-01

Graph 2. Paper Total Energy Sales Forecast



Since the Company filed for approval of NTEC, the load forecast used to justify the development of the facility, the 2017 AFR, has dramatically changed due primarily to the difference in forecasted and actual large power load.[60] The total energy sales forecast is significantly lower compared to the forecast used to justify NTEC. This is another example of how a high degree of customer concentration creates risk and costs that may be shared across customer classes. In the case of NTEC, large power load forecasts caused the need for marginal generation to be procured, but increased demand was never realized, resulting in regulatory and other costs being caused by large power customers but shared across all customer classes.

[60] Minnesota Public Utilities Commission Order Approving Affiliated-Interest Agreements with Conditions Docket No. E015/M/AI-17-568. Pg. 2-16

Q. How do the Company's customer-class ROEs prioritize Large Power customers?

A. The Company claims that the risks associated with Minnesota Power's LP customers should increase the Company's overall ROE, yet all customer classes are assigned an equal ROE cost allocation in the CCOSS.

Company witness Bulkley directly connects the Large Power customer risk with the Company's high ROE proposal, stating that "in light of the increased risk faced by the Company…due to Minnesota Power's high degree of customer concentration in industrial customers operating in cyclical industries…it is reasonable to place the requested ROE for Minnesota Power towards the high end of [the considered] range."[61] The witness also cited industry literature indicating that "increased risk associated with a more concentrated customer base will have the effect of increasing a company's cost of equity."[62] Indeed, the Company asserts that credit agencies have noted the risks of the Company's customer concentration and that such risk partially contributed to S&P downgrading ALLETE in 2020.[63]

Despite the contribution of Large Power customer risk to heightening Minnesota Power's company-wide ROE, the Company has allowed the ROE-

[61] Bulkley Direct Testimony at 106.
[62] Bulkley Direct Testimony at 40.
[63] Bulkley Direct Testimony at 47.

related costs of that risk to be spread over all classes, who all face the same ROE within the Company's cost of service study.

Q. How do you recommend the Company remedy the inconsistent customer class ROEs?

A. I recommend that the Commission increase the individual customer class ROE cost allocation for the Large Power customers within the cost of service study, which would increase the amount of revenue requirement allocated to the Large Power class. The increase in the Company-wide ROE that is attributable to Large Power customer risk should be borne by the Large Power class, not by other customer classes, through an increase in its own class-specific ROE and a commensurate decrease across the other customer classes.[64] Increasing total Company ROE, without increasing the Large Customer class's ROE in the cost of service study, creates a clear cross-subsidization and cost shift to other customer classes.

Q. How does the Company's allocation of regulatory costs prioritize Large Power customers?

A. The risks associated with Minnesota Power's LP customers trigger significant regulatory costs, yet the LP class is not allocated the majority of regulatory costs in the Company's CCOSS.

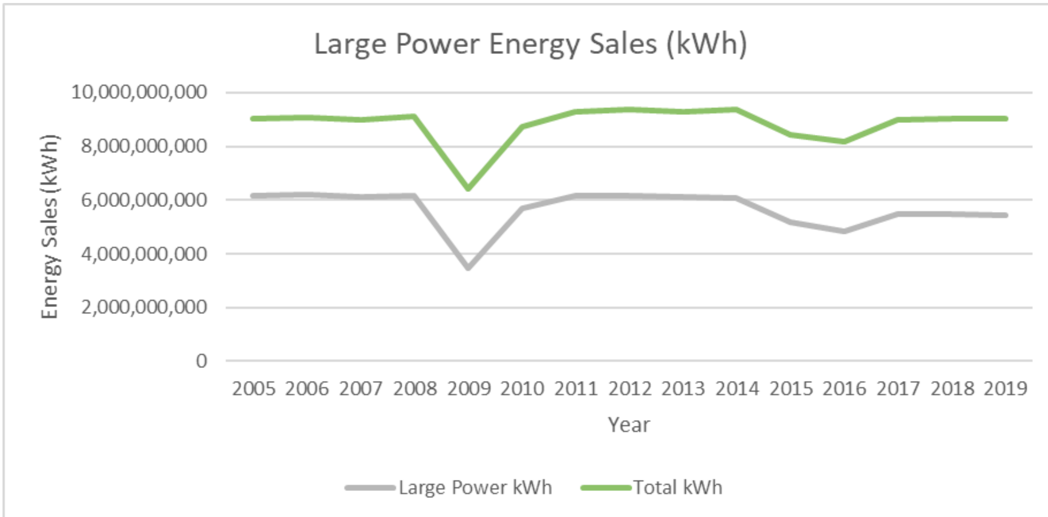
[64] I take no position on the Company's proposed overall ROE or the methodology therein.

Minnesota Power's justification for its sales true-up mechanism makes very clear that its Large Power customers cause regulatory costs, particularly those associated with a rate case. The fact that the mechanism "will help the Company stay out of future rate cases that are triggered solely by LP operations"[65] indicates that the LP class's revenue volatility can indeed independently trigger rate cases and all associated rate case costs.

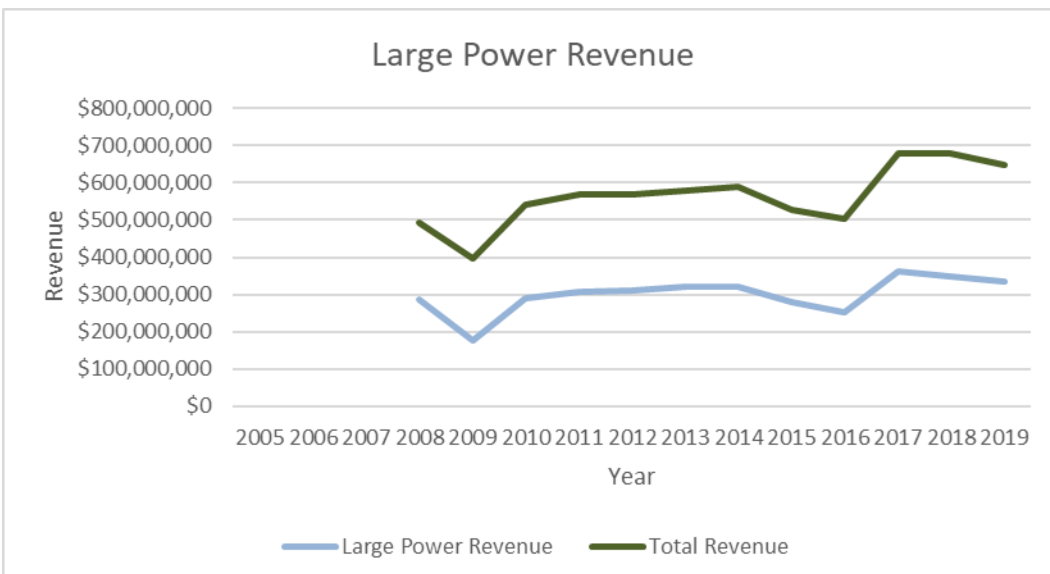
In fact, there is evidence that at least three of five rate cases over the past 10+ years all happened after LP sales declines. The Company filed general rate cases in 2008, 2009, 2016, 2019 (withdrawn due to the COVID-19 pandemic), and 2021. The charts below show the changes in energy sales and revenue for large power customers. In 2009, the Company saw a 44% decline in energy sales to large power customers from the previous year.[66] Between 2014 and 2016, the Company saw a 21% decline in energy sales. This resulted in a 39% and 22% decline in revenue from large power customers between 2008-2009 and 2014-2016, respectively. In the present rate case (2021), the Company has stated clearly throughout its filing that its stated need to increase rates owes to a decline in LP sales. Clearly, at least three of the five rate cases in the past 10+ years occurred as the Company experienced a decline in energy sales and revenue from the large power customer class.

[65] Frederickson Direct Testimony at 80.
[66] CUB IR 008.01 Attachment in E015/GR-19-442.

Graph 3. Large Power Energy Sales



Graph 4. Large Power Revenue



If the Large Power customers are solely responsible for triggering a rate case, the costs associated with that rate case should be directly assigned to that customers class, as that would be consistent with cost causation. However, that is not how regulatory costs, including a subset of rate case expenses, are treated in the Company's cost of service study. Despite LP customers directly causing significant regulatory costs, Minnesota Power does not directly allocate any regulatory expenses to the Large Power class.[67] This is another example of a likely inequitable cost shift from the Large Power class to other customer classes.

Q. How does the Company's allocation of production demand costs prioritize Large Power customers?

A. Minnesota Power has proposed to change its longstanding production demand allocation approach for a new approach, which allocates the second-most costs to the residential class and the second-least costs to the Large Power class, out of the seven Company peak methods evaluated.[68] I discussed this issue in more depth above in Section IV, and it is another example of how Minnesota Power has an economic incentive to make unreasonable arguments to support its Large Power customers.

Q. How do you recommend the Commission factor Large Power customer risk into its decision making in this case?

A. Minnesota Power has a strong economic incentive to create opportunities for Large Power customer load expansion (e.g., NTEC) and keep their rates low by

[67] OAG IR 7001.01 Attach TS, tab 19.

[68] Shimmin Direct Testimony at 32. Although I do not agree with the Company's method for indexing and comparing the various production demand allocation approaches – which I will describe further, later – the Company clearly supports its own indexed comparison, and, therefore, implications of the production allocation method it chose using that index.

shifting related costs to other customer classes. I have touched on a few of these explicit examples, but this is far from an exhaustive list. The impact that the Large Power customers have on Minnesota Power is pervasive and runs throughout its business. However, the impacts, such as the exact increase in Large Power class ROE, are difficult to accurately quantify. For this reason, traditional regulatory approaches, such as relying on a cost of service model to inform revenue apportionment, are not as accurate or useful for decision making in Minnesota Power's case. Therefore, I recommend that the Commission consider the unique risk factors associated with the Large Power class when making decisions in this case including, but not limited to, revenue apportionment.

VI. REVENUE APPORTIONMENT

Q. What is revenue apportionment?

A. Revenue apportionment refers to the change in each customer class's revenue requirement that will be implemented in rate design.

Q. Could the Large Power customer risk discussed above, in Section V, impact the Company's revenue apportionment?

A. Yes. A utility's revenue apportionment and resulting rate design is typically informed – but not dictated – by its CCOSS results. Given the costliness of the LP class risk and volatility, the socialization of many of those costs across customer classes, and the resulting subjective nature of the Company's CCOSS, using the CCOSS to closely inform revenue apportionment would not accurately represent the true cost responsibility of the various customer classes.

Indeed, Minnesota Power did not propose to align its revenue apportionment and resulting rate design with its CCOSS results, but instead proposed "an equal increase adjustment of 18.22 percent across all General Rates for sales by rate class."[69]

Q. Do you agree with the Company's proposed revenue apportionment?

A. While the Company's equal increase adjustment is far superior to using the CCOSS results, I do not believe that it adequately accounts for the large power risk that I have previously discussed, nor for the "adverse impact on the Residential customer class" that the Company claims to keep "in mind."[70]

Regarding large power risk, there are likely many more examples than those that I've already highlighted (e.g., class ROE, regulatory costs, etc.) of the Company incurring power system, financial, and regulatory costs due to Large Power customers but spreading them across all customer classes. Assigning an equal percentage increase across customer classes to make up the Company's

[69] Peterson Direct Testimony at 6.
[70] Peterson Direct Testimony at 6.

claimed revenue deficiency may under-allocate costs to the Large Power classes and over-allocate to others, such as the residential class.

Regarding the particular attention paid to the residential class, I note the Commission's prior guidance on the interim rate increase, from the December 2021 Order Setting Interim Rates. The Commission considered numerous factors, such as the COVID-19 pandemic and inflation, that "weigh against increasing rates for the residential class"[71] and found that the Company should only increase residential rates by 50% of the rate increase for other classes.[72] The circumstances under which the Commission made its order on interim rate have not materially changed in the intervening months. In fact, inflation has increased dramatically in the new year, further straining household budgets. Residential arrears also continue to increase, and total residential past-due is up 22%, or $831,526 since December 2021, as of February 2022.[73]

Q. What do you recommend for the Company's revenue apportionment in this case?

A. I recommend that the Commission replicate its approach from the order on interim rates and assign half of the total percentage rate increase to the

[71] *Order Setting Interim Rates* in Docket No. E-015/GR-21-335. MN Public Utilities Commission. December 30, 2021. At 5.

[72] Specifically, "Minnesota Power may implement its annual interim rate revenue increase of $87.3 million, or 14.23%...with the following exception: Due to exigent circumstances, Minnesota Power must limit the rate increase for residential customers to 7.11%, subject to possible adjustment" *Ibid*.

[73] Residential Status Reports, Minnesota Power, in Docket No. E,G999/CI-20-375. MN Public Utilities Commission. December 2021 and February 2022.

residential class with equal and commensurate increases for the other customer classes – including the Large Power customer class.

VII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Ron Nelson

Senior Director

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Education

MS, Agricultural and Resource Economics
Colorado State University, 2013

BA, Environmental Economics
Western Washington University, 2011

Work Experience

Senior Director

Strategen / Portland, OR / 2018 - Present

+ Subject matter and testimony expert in advanced rate design, embedded and marginal cost of service modeling, performance-based regulation, and DER integration and compensation.
+ Designing policies and programs to advance deployment of distributed energy resources, demand-side management programs, energy storage and grid integration

Economist

Minnesota Attorney General's Office / St. Paul, MN / 2013 - 2017

+ Provided expert testimony on cost of service modeling, rate design, grid modernization and utility business models
+ Analyzing issues related to conservation incentive programs, value of solar, grid modernization, performance-based regulation, renewable energy program design, and MISO

Graduate Research Associate

Colorado State University / Fort Collins, CO / 2011 - 2013

+ Analyzed the ongoing impact of the 2011 drought in Colorado
+ Wrote and obtained grants, setting and managing their budgets, and delivering final research projects

Economic Research Assistant

Washington State University / Mount Vernon, WA / 2009 - 2011

+ Developed a payment for ecosystem services program for The Nature Conservancy
+ Established ecological metrics that could be monetized into economic benefits and estimating the benefits and costs to farmers

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Expert Testimony

Green Mountain Power Corporation (DKT: 21-3707-PET) On Behalf of Green Mountain Power
Multi-Year Regulation Plan
Direct Testimony with Matt McDonnell

Public Service of Oklahoma (DKT: 202100055) On Behalf of AARP
ECOSS and Rate Design
Responsive Testimony

Duquesne Light Company (DKT: R-2021-3024750) On Behalf of the PA OCA
Transportation Electrification, Load Control
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

PECO (DKT: R-2021-3024601) On Behalf of the PA OCA
Transportation Electrification, Load Control
Direct (note: please type in the docket number, the testimony cannot be directly referenced)

Rocky Mountain Power (DKT: 20-035-04) On Behalf of the Utah Office of Consumer Services
Embedded COS, Rate Design, and AMI rollout
Direct

Minnesota Power* On Behalf of the MN CUB
ECOSS and low income rate design

Pennsylvania Power and Light: DER Management Petition (DKT: P-2019-3010128) On Behalf of the PA OCA
DER integration
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

Public Service of New Hampshire (dba Eversource Energy) (DKT: DE 19-057) On Behalf of the NH OCA
Embedded and marginal COS, Rate Design, and PBR
Direct

Liberty Utilities (DKT: DE 19-064) On Behalf of the NH OCA
Marginal COS, Rate Design, decoupling and PBR
Direct

Oklahoma Gas and Electric (DKT: 201800140) On Behalf of AARP
Rate Design and CCOSS
Direct

Vectren Energy Delivery of Ohio (DKT: 18-0298-GA-AIR) On Behalf of the Environmental Law and Policy Center
CCOSS and Rate Design
Direct | Supplemental | Case link

*Settled before direct was filed

Ron Nelson

Senior Director

Expert Testimony Continued

Commonwealth Edison (DKT: 18-0753) On Behalf of the IL AG
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case link

Ameren Illinois Company (DKT: 18-0537) On Behalf of the IL AG
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case file

Public Service Company of Oklahoma (DKT: 201800096) On Behalf of AARP
Formula Rates, Performance Metrics, Rate Design, and CCOSS
Direct

Oklahoma Gas and Electric (DKT: 201700496) On Behalf of AARP
CCOSS and Revenue Apportionment
Responsive | Case link

Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG
CCOSS, Rate Design, and the Utility Business Model
Surrebuttal | Rebuttal: | Testimony | Case Link

Otter Tail Power (DKT: E-002/GR-15-1033) On Behalf of the MN OAG
Marginal and Embedded CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Case link

Xcel Energy (DKT: E-002/GR-15-826) On Behalf of the MN OAG
CCOSS, Rate Design, and Performance-Based Regulation
Direct | Rebuttal | Surrebuttal |Case link

Minnesota Energy Resources Corp. (DKT: G-011/GR-15-736) On Behalf of the MN OAG
CCOSS and Rate Design
Direct : | Rebuttal | Surrebuttal | Case link

CenterPoint Energy (DKT: E-002/GR-15-424) On Behalf of the MN OAG
CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Surrebuttal | Case link

Dakota Energy Association (DKT: E-002/GR-14-482) On Behalf of the MN OAG
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal | Case link

Xcel Energy (DKT: E-002/GR-13-868) On Behalf of the MN OAG
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal: Case Link

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Senior Director

Expert Testimony Continued

Minnesota Energy Resources Corp. (DKT: G-011/GR-13-617) On Behalf of the MN OAG
CCOSS
Direct | Surrebuttal | Case Link

CenterPoint Energy (DKT: G-008/GR-13-316) On Behalf of the MN OAG
CCOSS
Direct: | Surrebuttal | Case Link