Surrebuttal Testimony
Michael A. Peppin

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-15-826
Exhibit___(MAP-3)

Class Cost of Service Study
and
Selected Rate Design

October 18, 2016
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.
A. My name is Michael A. Peppin. My title is Principal Pricing Analyst.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?
A. Yes. I filed Direct Testimony and Rebuttal Testimony on behalf of Northern States Power Company ("Xcel Energy" or the "Company") presenting the Company's Class Cost of Service Study ("CCOSS") and a portion of the Company’s proposed rate design.

Q. DID ANY INTERVENERS PROVIDE REBUTTAL TESTIMONY REGARDING THE COMPANY’S PROPOSED CCOSSS AND RATE DESIGN TOPICS INCLUDED IN YOUR DIRECT TESTIMONY?
A. Yes. The following witnesses provided rebuttal testimony related to the Company’s proposed CCOSSs and the rate design topics included in my Direct Testimony:

- Minnesota Department of Commerce, Division of Energy Resources ("Department") witness Michael N. Zajicek;
- Office of the Attorney General – Antitrust and Utilities Division ("OAG") witnesses Ron Nelson and John Lindell;
- Xcel Large Industrial Customers ("XLI") witness Jeffry Pollock.

My Rebuttal Testimony responded to the detailed issues raised in the direct testimony of the above-mentioned witnesses. While I do not here provide a full restatement of those issues, my Rebuttal Testimony:
- provided information to support the statistical validity and robustness of the Company’s Minimum System and Zero Intercept studies;
- noted that the Minimum System and Zero Intercept studies were based on the actual costs of an adequate and representative sample of distribution work orders that were completed over a five-and-a-half-year time frame;
- agreed with Department witness Mr. Michael Zajicek that normalizing the five and a half years of construction cost data to the current year using the Handy Whitman index would improve the accuracy of the results;
- provided evidence that basing the D10S capacity allocator on class loads coincident with a MISO-specified peak hour does not provide a cost allocator that reflects cost causation but would instead result in an allocator that shows large unexplained variation between rate cases;
- agreed that MCC witness Ms. Kavita Maini’s suggested changes to the cost allocators for the Conservation Improvement Program (“CIP”), Renewable Development Fund (“RDF”) and solar purchased power agreement (“PPA”) costs deserve further consideration. However, we believe that the appropriate venue for these discussions is in the appropriate rider docket; and
- agreed with XLI witness Mr. Jeffry Pollock’s suggested changes to the D60Sub allocator. We also agreed with his suggestion that costs of direct assignment facilities no longer serving customers should be allocated to all customer classes. And finally, the Company agreed to look at loss factor study methodologies for its next rate case filing.
Q. **What is the purpose of your Surrebuttal Testimony?**

A. The purpose of my Surrebuttal Testimony is to:

- Provide a general response to OAG witness Mr. Ron Nelson’s criticism regarding the separation of distribution costs into customer and capacity-related components.
- Respond to Mr. Nelson’s recommended use of multiple CCOSS methods for the purpose of revenue apportionment.
- Provide a final recommendation regarding the calculation of the D10S capacity allocator.

**II. Separation of Distribution Costs Into Customer and Capacity-Related Components**

Q. **In past rate cases, has the classification of distribution plant into customer and capacity-related components been disputed?**

A. No. To my knowledge, all Minnesota utilities have used, and the Commission has accepted, the minimum system approach for classifying distribution plant costs into customer and capacity components since the 1980s. This separation has not been an area of disagreement.

Q. **In recent rate cases, has the OAG supported the separation of distribution costs into customer and capacity-related components?**

A. Yes. Although the OAG raised an issue with the mechanics of the Minimum System Study in the Company’s last rate case in Docket No. E002/GR-13-868, the concept of a customer-related component to distribution costs has not been disputed by the OAG. At the conclusion of the Company’s last rate...
case, the OAG requested that the Company update its Minimum System Study and also complete a Zero Intercept Study. The Company has complied with those requests, and completed well-documented, robust studies.

Q. Mr. Nelson has suggested that the Commission should also consider a version of the CCOSS model that classifies distribution plant as 100 percent capacity-related (basic customer method) and a second version that classifies distribution plant as 55 percent energy-related and 45 percent capacity-related (peak and average method). Should the Commission consider these alternative CCOSS versions?

A. No. These alternative allocation methods are unsupportable for the following reasons, and should not be considered as representative of class cost responsibility. First, the Northern States Power Company-Minnesota (“NSPM”) system load factor (55 percent) which is required in the Peak and Average calculation has absolutely no relationship to the distribution system. Depending on the customers served by a distribution feeder, the load factor of a given feeder can vary from less than 20 percent to more than 80 percent.\(^1\) More importantly, the classification of distribution costs into both customer and capacity components is an undisputed and long-settled issue. Including these alternative versions of the CCOSS model simply adds confusion to a well-established record. Also, as noted in my earlier testimony, as well as the testimony of other witnesses to this proceeding, these alternative methods find no support in Minnesota precedent, or the adjacent states of North Dakota,

\[1\] The load factor of a distribution feeder equals the average load in kW on the distribution feeder divided by the feeder’s peak load.
South Dakota and Wisconsin. Allocating distribution costs using an allocator with an energy component has no support in other jurisdictions around the country for electric utility rate cases.

Q. Department witness Mr. Zajicek stated in his Rebuttal Testimony that he would not oppose using a peak and average allocator to allocate distribution system costs that have been classified as demand-related. Do you agree with that allocation method?
A. No. While the distribution system is designed to account for losses, it is designed to account for maximum losses during peak times on a distribution feeder. These losses are unquestionably demand-related. As such, using an allocator that has an energy component is not appropriate. There is no energy component to the distribution system as clearly stated in the National Association of Regulatory Utility Commissioners (“NARUC”) manual.

Q. In future rate cases, what method should the company use to classify distribution system costs?
A. Based on the direct and rebuttal testimony of all parties and a review of the methods that are used regionally, I believe that the Minimum System Study should continue to be used to classify costs. The method should continue to include an adjustment for the load-carrying capacity of the minimum-sized equipment. Using the minimum-sized method is also consistent with the method used in the Company’s rate cases since the 1990s. A comparison of CCOSS results using the different methods for classifying distribution system costs is shown in Table 14 of my Direct Testimony, Exhibit___(MAP-1). CCOSS results using the recommended minimum system method are shown on columns 4 and 5 of Table 14.
III. USE OF ALTERNATIVE CCOSS METHODS
FOR REVENUE APPORTIONMENT

Q. OAG witness Mr. Nelson has stated the Commission should consider multiple versions of the CCOSS when determining revenue apportionment. How do you respond?

A. I disagree with that recommendation, and note that Mr. Nelson limits his recommendation to differences in the allocation of distribution costs. In every rate case there are differences of opinion among parties on how multiple-cost areas should be classified and allocated, with some costs receiving more focus than others. In the Company’s last five rate cases (Docket Nos. E002/GR-05-1428, E002/GR-08-1065, E002/GR-10-971, E002/GR-12-961 and E002/GR-13-868), the cost area that has received the most scrutiny is the classification and allocation of fixed production plant costs. Alternative methods have been proposed by multiple parties. In the Company’s 2012 rate case (Docket No. E002/GR-12-961), the Company showed CCOSS results using seven different classification and allocation methods for fixed production plant costs that have been used by electric utilities regionally. In the Company’s last rate case, Ms. Kavita Maini, representing the Minnesota Chamber of Commerce, requested that the Commission consider the results of multiple CCOSS versions when determining revenue apportionment, but the Commission did not approve the use of multiple methods of allocating fixed production costs for the final revenue apportionment.

Q. What is the revenue requirement impact of using alternative methods to classify and allocate fixed production costs?
A. Using the CCOSS provided with my Direct Testimony in the present rate case, depending on which of the seven methods is used for classifying and allocating fixed production plant costs, the revenue requirement for the residential class could change by nearly $58 million dollars. There is an additional method, namely the fixed variable 1CP method, that although less common but still in use nationally, would increase the residential class revenue requirement by over $100 million. The fixed variable 1CP allocation method was recommended by MCC witness Ms. Maini in the Company’s last two rate cases.

Q. DO DIFFERENCES OF THAT MAGNITUDE DEMONSTRATE THE REASONABLENESS OF CONSIDERING MULTIPLE METHODS?

A. No. Including multiple methods only makes sense if their inclusion is based on sound economic principles, and if the methods used reflect the underlying reasons for incurring the costs in question. Including methods that do not reflect cost causation simply adds confusion to an already complicated record.

Q. IN PRIOR ELECTRIC RATE CASES HAS THE COMMISSION EVER USED THE RESULTS FROM MULTIPLE CCOSS VERSIONS WHEN IT DETERMINED REVENUE APPORTIONMENT?

A. To the best of my knowledge, it has not. In prior rate cases, the Commission has carefully considered the record and made definitive decisions on the classification and allocation methods that should be used for multiple cost items. Its decisions are based on the premise that the methods selected most accurately reflect what caused those costs to occur.
Q. **Mr. Nelson has also stated that the CCOSS model is an inherently imprecise tool based on numerous subjective judgments by the analyst. How do you respond?**

A. The Company’s CCOSSs have been closely examined by the Commission in five recent rate cases since 2005. The CCOSS submitted by the Company in the current case reflects the classification and allocation methods which the Commission, after careful consideration, has approved or specifically ordered in these prior cases.

Q. **In the current case, did Mr. Nelson recommend the Commission use multiple CCOSS versions when it determines revenue apportionment?**

A. Yes, Mr. Nelson recommends the Commission use CCOSS versions that utilize the basic customer, peak and average, and minimum system methods for classifying and allocating distribution plant costs.

Q. **If the Commission agrees that multiple CCOSS models should be used for revenue apportionment, should it limit its review to only those versions that vary distribution plant classification and allocation methods?**

A. No. While I don’t agree with the OAG’s recommendation, if the Commission agrees to use multiple versions, its review should also include other CCOSS model variations, including those related to fixed production plant costs.
IV. CALCULATION OF THE D10S CAPACITY ALLOCATOR

Q. DO BOTH THE OAG AND DEPARTMENT MISREPRESENT HOW THE COMPANY AND MISO DETERMINE PRODUCTION CAPACITY REQUIREMENTS?
A. Yes. As I explained in my Rebuttal Testimony, NSP’s System peak demand is the primary indicator that determines the need for additional production capacity, and the Midcontinent Independent System Operator (“MISO”) does not specify a peak hour for utility production planning.

Q. IN ORDER TO REFLECT HOW THE COMPANY AND MISO DETERMINE PRODUCTION CAPACITY REQUIREMENTS AND FUTURE CAPACITY ADDITIONS, HOW SHOULD THE D10S BE CALCULATED?
A. First, the NSPM System peak should be used, with the D10S allocator based on class loads coincident with the NSPM System peak. Since the System peak is adjusted to include a 95 percent coincidence factor and a MISO required 7.1 percent reserve margin,\(^2\) class loads should be adjusted accordingly. However, since all classes are adjusted by the same percentages, the D10S allocator is mathematically the same as simply using Minnesota class loads coincident with the NSPM System peak.

Q. IS IT TRUE, AS MR. NELSON STATED IN HIS DIRECT TESTIMONY, THAT MISO WILL BE SWITCHING TO A SEASONAL, SUMMER AND WINTER CAPACITY RESERVE REQUIREMENT?
A. MISO has been in discussions regarding this possible change for several years. However, with many planned power plant maintenance outages scheduled for

\(^2\) After filing direct testimony, the Company’s planning reserve margin was increased to 7.6 percent for the June 2016 – May 2017 planning year, and will again increase to 7.8 percent for the June 2017 – May 2018 planning year.
the winter months, a shift to a winter capacity reserve requirement would significantly narrow the available window for these outages to the shoulder (spring and fall) months. During these discussions, MISO’s projections on when a seasonal capacity requirement can be implemented have shifted back in time. Presently, implementation is being suggested beginning with the 2019-2020 MISO planning year. Any switch to a seasonal capacity requirement must be filed with and accepted by the Federal Energy Regulatory Commission (“FERC”), and this filing has yet to occur.

In spite of a possible MISO shift to a seasonal capacity requirement, which remains uncertain given that it is subject to MISO’s stakeholder process and would require FERC acceptance, NSP will remain a summer peaking utility with its capacity requirement based on its summer peak.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A. Below is a summary of my Surrebuttal Testimony:

• The classification of distribution plant costs into customer and capacity-related components is an issue that was appropriately determined long ago and has not been disputed by any party until the current rate case. The OAG’s recommendation to include CCOSS versions that include the “basic customer” and “peak and average” methods for classifying and allocating distribution plant costs is not defendable based on economic theory or past practice.

• The Minimum System and Zero Intercept studies completed by the Company and submitted in this filing are robust and well-documented
studies based on the current costs of nearly 1,900 actual distribution work orders.

- The recommendation by the OAG to use multiple CCOSS versions for revenue apportionment should be disregarded. The Company’s CCOSS has been closely examined by the Commission in five recent rate cases. The CCOSS model submitted by the Company in the current case reflects the classification and allocation methods which the Commission, after careful consideration, has approved or explicitly ordered in these cases.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.