Rebuttal Testimony and Schedules
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-2)

Class Cost of Service Study
And
Selected Rate Design

September 23, 2016

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Schedules

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 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 INTERVENORS PROVIDE DIRECT TESTIMONY REGARDING THE COMPANY'S PROPOSED CCOSSS AND RATE DESIGN TOPICS INCLUDED IN YOUR DIRECT TESTIMONY?

A. Yes. The following witnesses provided 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") witness Ron Nelson;
- Minnesota Chamber of Commerce ("MCC") witness Kavita Maini;
- Xcel Large Industrial Customers ("XLI") witness Jeffry Pollock; and
- The Industrial, Commercial and Institutional customer group ("ICI Group") witness Geoffrey Inge.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I discuss the CCOSS as it relates to the August 16, 2016 Stipulation of Settlement ("Settlement"). I also respond to the direct testimony of the witnesses listed above regarding the Company's proposed CCOSSs and selected rate design topics.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. I present my testimony in the sections as outlined below.

- The Settlement and the CCOSS
- Cost Classification and Allocation Recommendations
- Conclusion

II. SETTLEMENT REVENUE APPORTIONMENT AND THE CCOSS

A. The Settlement and the CCOSS

Q. THE SETTLEMENT DID NOT ADDRESS ISSUES RELATED TO CLASS COST OF SERVICE OR RATE DESIGN. HOW DO YOU PROPOSE THE COMMISSION DETERMINE REVENUE APPORTIONMENT?

A. The agreement reached in the August 16, 2016 Settlement did not provide the line-by-line jurisdictional cost detail typically used in developing a CCOSS. As mentioned in the Company's response to the Clean Energy Organizations' ("CEO") Information Request ("IR") No. 19, included as Exhibit___(CRB-2) Schedule 1, the Company does not intend to develop a CCOSS that reflects the 2016 test year Settlement revenue requirement. We recommend that the CCOSS filed with my Direct Testimony be factored down to meet the 2016 Settlement revenues for revenue apportionment purposes. The Company's approach to the Settlement-level revenue apportionment is further discussed in the Rebuttal Testimony of Company witness Mr. Steven V. Huso.

B. Class Cost Classification and Allocation Recommendations

Q. INTERVENING PARTIES MADE SEVERAL RECOMMENDATIONS REGARDING COST CLASSIFICATION AND ALLOCATION ISSUES. HOW DO YOU RESPOND TO THOSE RECOMMENDATIONS?

A. My Rebuttal Testimony will address the following cost classification and allocation issues as they relate to the CCOSS:

- Classification and Allocation of Distribution Costs (Department witness Mr. Zajicek; OAG witness Mr. Nelson; MCC witness Ms. Maini; and XLI witness Mr. Pollock)
- The D10S Allocator (MCC witness Ms. Maini; XLI witness Mr. Pollock; and ICI witness Mr. Inge)
- The Calculation of the D60Sub Allocator (XLI witness Mr. Pollock)
- Loss Factors Used in the CCOSS (XLI witness Mr. Pollock)
- Direct Assignment and Allocation of Transmission and Distribution Facilities (XLI witness Mr. Pollock)
- Allocation of CIP CCRC Costs Recovered in Base Rates (MCC witness Ms. Maini)
- Allocation of RDF Rider, CIP Rider and Solar PPA Costs (MCC witness Ms. Maini)

Based on my review of the direct testimony of intervening witnesses, my Rebuttal Testimony recommends cost classification and allocation changes that the Commission should consider.

1. Classification and Allocation of Distribution Plant Costs

a. The Purpose and Prevalence of Classifying Distribution Costs as Customer-Related

Q. IS IT WIDELY ACCEPTED THAT ELECTRIC DISTRIBUTION COSTS SHOULD BE CLASSIFIED AS BOTH CUSTOMER- AND DEMAND-RELATED?

A. Yes. It is widely accepted at the state, regional, and national levels that distribution costs are driven by two factors: 1) the number of customers on the distribution system, and 2) the demand those customers place on the system. With regard to the national prevalence of this classification, the National Association of Regulatory Utility Commissioners ("NARUC") manual clearly states that only demand and customer components should be considered in classifying distribution costs. Specifically, at Chapter 6, page 89 of the manual, NARUC states:

> To insure that (distribution) costs are properly allocated, the analyst must first classify each account as demand-related, customer-related or a combination of both.
>
> As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

Page 90 of the NARUC manual goes on to say:

> Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

With respect to the regional and state prevalence of the classification, all Commissions in the four-state region (Minnesota, North Dakota, South Dakota and Wisconsin) accept the customer- and demand-related components of distribution costs. Additionally, the Minnesota Public Utilities Commission has accepted the Minimum System method as a means to separate distribution facilities into demand and customer components since the 1980s.

Q. WHAT IS THE PURPOSE OF CLASSIFYING ELECTRIC DISTRIBUTION COSTS AS BOTH CUSTOMER- AND DEMAND-RELATED?

A. The purpose of this classification is to allocate costs according to causation. The *customer*-related portion of the distribution system makes service available to the customer. The balance of distribution system costs is *capacity*-related. The costs a utility incurs to connect a customer to the distribution grid without regard to the level of customer load is reasonably classified as customer-related and allocated based on number of customers. The capacity-related cost component – those that are not customer-related – has cost causation based on the level of power demanded by customers above the minimum customer-related level. These costs should be allocated on customer demand and are appropriate to recover through volumetric charges.

Q. CAN YOU PLEASE PROVIDE A REAL-WORLD EXAMPLE OF HOW DISTRIBUTION COSTS ARE INCURRED, CLASSIFIED, AND ALLOCATED?

A. Yes. Consider a distribution construction job where the Company deploys construction crews, bucket trucks, trenchers, and other equipment on site. Labor, equipment and overhead costs are incurred to dig trenches and set poles before any conductor or load-related costs are incurred. These are real distribution costs that the utility incurs before any load is planned for the system. Incremental costs are incurred to plan for and install load-related costs that make up the demand-related component of distribution system costs.

b. Alternative Classifications are Unsupportable

Q. DO YOU HAVE KNOWLEDGE OF ANY ELECTRIC UTILITY OR COMMISSION ORDER THAT CLASSIFIES DISTRIBUTION PLANT AS HAVING AN ENERGY COMPONENT?

A. I do not. The Department sought this information from OAG witness Mr. Nelson in Department IR No. 705. The OAG responded as follows:

> Mr. Nelson has not identified any electric utility rate cases that utilize the peak and average method to both classify and allocate distribution system costs . . .

Mr. Nelson's only reference to the actual application of the Peak and Average method is in the context of the classification and allocation of production plant investment. For distribution plant, his only reference for applying the Peak and Average method is for natural gas utilities. Recommendations to classify distribution costs using the peak and average method lack support in the record.

Q. IS IT APPROPRIATE TO CLASSIFY DISTRIBUTION PLANT AS HAVING AN ENERGY COMPONENT?

A. No. In addition to lacking support in the record, it is inappropriate to classify distribution costs as having an energy component because there is no energy component driving distribution plant investment. Transmission and distribution systems are sized so as to serve the maximum demand of customers served by the network. As referenced by the Company's response to OAG IR No. 706, included as Schedule 2 to my Rebuttal Testimony, this maximum demand is adjusted to account for losses on the distribution system.

Q. IS IT APPROPRIATE TO CLASSIFY AND ALLOCATE DISTRIBUTION COSTS USING THE "BASIC CUSTOMER" METHOD?

A. No. The "Basic Customer" method is the most extreme position that can be defined for this issue. This method allocates primary conductor, secondary conductor and transformers only on demand with no recognition of the customer component. Further, it ignores cost causation and the well-established tenet that the addition of customers is a significant determinant of distribution system costs.

Additionally, allocating costs only on demand ignores the existence of significant economies of scale as the capacity of distribution equipment increases. For example, the installed cost per kVa for a 100 kVa overhead transformer is $46 per kVa, while the cost per kVa for a 10 kVa overhead transformer is $191 per kVa. Similar economies of scale exist for conductors. For example, the installed cost of 1 Phase 2 ACSR overhead primary conductor with a current carrying capacity of 200 Amps is $8.12 per foot or $.0406 per foot per Amp. By comparison the cost of 3 Phase 556 AL overhead primary conductor with a current carrying capacity of 2,295 Amps is $30.88 per foot or $.0135 per foot per Amp. Allocating these costs solely on customers' demand ignores these economies of scale.

These extreme alternative approaches to distribution cost allocation (Peak, Average, and Basic Customer) establish an unrealistically narrow definition of the issue. These approaches are presented in support of taking a weighted average of a set cost study results, yet they drive an unjustifiably narrow and extreme range of cost allocations.

Q. DO THE ALTERNATIVE DISTRIBUTION COST ALLOCATION APPROACHES PROVIDE THE APPROPRIATE COST BASIS FOR DETERMINING REASONABLE FIXED CUSTOMER CHARGES?

A. No. Rather than providing an appropriate cost basis, the alternative approaches instead distort the cost basis underlying these customer charges. The wide departure from an accurate and realistic representation of cost causation that results from the OAG's alternative distribution cost allocations also fails to recognize a large share of customer-related costs that are clearly fixed and that have no relation to customer energy usage. For the foregoing reasons, the Company believes these approaches are inappropriate, unreasonable, and unsupportable.

Q. IS A COST IRRELEVANT BECAUSE IT IS A FIXED COST OR IS CONSIDERED A "SUNK COST" AS SUGGESTED BY OAG WITNESS MR. NELSON?

A. No. The fact that a substantial portion of utility costs are fixed or can be considered a "sunk cost" is simply a characteristic of utility service. Fixed or "sunk" costs exist and still need to be recovered from customers in a reasonable relationship with cost causation as determined by accurate representation in a class cost of service study.

c. The Minimum System Concept is Accurate and Based on Actual Costs

Q. WHAT DATA DID THE COMPANY USE TO SUPPORT ITS MINIMUM SYSTEM ANALYSIS?

A. The Minimum System is not a hypothetical system, but is based on the minimum-sized equipment currently installed and the actual costs for installing that equipment. As stated previously, there are real costs the utility incurs before any customer load is planned for the distribution system. The Company used actual cost installation data from distribution Work Orders for equipment configurations that comprise at least 90 percent or more of the equipment present on the distribution system. The Company's analysis also accounted for the load carrying capacity of the Minimum System.

d. The Minimum System Approach Appropriately Accounts for Customer Density

Q. DOES THE MINIMUM SYSTEM APPROACH ACCOUNT FOR CHANGES IN CUSTOMER DENSITY?

A. Yes. In the Company's analysis, all costs were normalized on a per-foot basis for conductors and on a per-unit basis for transformers. These unit costs are derived from Work Orders that cover rural, suburban and urban areas. When infill of the distribution system occurs, whether it be expansion on the periphery or within the existing system footprint, new primary and secondary conductors are typically required with these Work Orders, along with new transformers to serve the added customers. This is also true as land use changes within the distribution system, such that new transformers are typically required to serve the new load. Using costs-per-unit appropriately accounts for the changes in customer density.

e. Use of Minimum-Sized Equipment

Q. DID THE COMPANY USE THE SMALLEST DISTRIBUTION EQUIPMENT CURRENTLY BEING INSTALLED ON THE SYSTEM FOR THE MINIMUM SYSTEM STUDY?

A. Yes, with two exceptions: overhead and underground (pad-mounted) transformers. As explained in the Direct and Rebuttal Testimony of Company witness Ms. Kelly A. Bloch, the Company used smaller transformers than the minimum-sized transformers that are currently installed. Using smaller sized transformers in the Minimum System analysis benefits residential class customers.

It should be noted that the NARUC manual does not prescribe whether the minimum size should be based on the minimum-sized equipment currently installed, historically installed, or minimum size needed to meet safety requirements. Also, as stated on pages 28-36 of my Direct Testimony, the Company completed both Minimum System and Zero Intercept studies. For a given property unit, a hybrid of the two methods was used, in that the Company used the method in direct testimony that provided the lower customer-related component. For each of the six property units, the per-unit costs used to determine the customer versus capacity-related split were the same or lower than unit cost of the smallest sized equipment present on the distribution system. As shown on page 36, Table 14 of my Direct Testimony, this significantly benefits residential class customers.

f. Study Costs are Supported by Actual Costs

Q. HOW DID THE COMPANY SUPPORT THE COST ESTIMATES USED IN ITS MINIMUM COST ANALYSIS?

A. The Company supported its cost estimates by relying on nearly 1,900 distribution system Work Orders. Pages 7-12 of Ms. Bloch's Rebuttal Testimony detail the steps taken by the Company to gather and filter the available Work Orders and to develop accurate estimates of installed costs. As noted on page 95 of the NARUC manual, a thorough review of the unit cost data is common with outlier data deleted. The Company also provided an Excel file with the following detail on each of the 1,900 individual Work Orders:

- Property Unit Installed (e.g. Underground Primary)
- Equipment Configuration Installed (e.g. 1/0 AL 1 Phase)
- Number of Units Installed with the Work Order (footage for conductor or number of transformers)
- Detailed Costs by Component
    - Company Labor
    - Company Overtime Labor
    - Contract Labor
    - Contract Overtime Labor
    - Equipment and Vehicle Costs (Trucks, Trenchers, etc.)
    - Material Costs (Conductor, Poles, Transformers, etc.)
    - Total Installed Cost for the Work Order
    - Final Cost per Unit for the Work Order

The Company's support additionally included 1) detailed calculations for determining average installed costs for each material configuration and 2) the ultimate calculations to determine the customer versus demand splits using both the minimum system and zero intercept methods. OAG witness Mr. Nelson's concern that the Company did not sufficiently explain its cost estimates is obviously unfounded. As he had requested in the Company's last rate case in Docket No. E002/GR-13-868, Mr. Nelson had all the data and calculations needed to verify the Company's analysis.

g. Average Installed Book Costs

Q. WAS THE COMPANY REQUIRED TO USE THE AVERAGE INSTALLED BOOK COSTS IN ITS MINIMUM SYSTEM STUDY AND ZERO INTERCEPT ANALYSIS?

A. No. The steps required to complete both Minimum System and Zero Intercept studies are listed on pages 30-33 of my Direct Testimony. Both studies require accurate estimates of installed costs. The Minimum System Study requires an estimate of the installed cost of the minimum-sized equipment and the installed costs of the entire distribution system.

It should be noted that in the Company's last rate case, the OAG requested that the Commission order the Company to update its Minimum System Study and complete a Zero Intercept Study in its next rate case. Completing the Zero Intercept Study required the Company to calculate costs not just for the minimum-sized equipment, but for 68 separate equipment configurations.

Having accurate and comparable cost data is one of the most important elements of both minimum system and zero intercept studies. Page 90-91 of the NARUC manual states the following regarding cost estimates:

> ***Normally*****,** the average book cost for each piece of equipment determines the price of all installed units.

Using costs booked in a utility's accounting system is one method for developing installed cost estimates. Due to changes in the Company's accounting records, however, booked costs based at an equipment-size level are no longer available. There are potential significant inaccuracies when using booked costs, however. Booked costs typically represent 30 or more years of equipment vintages. Given the significant swings over time in commodity costs, annual construction activity and the ongoing changes in the equipment sizes and types in use on the distribution system, the different cost vintages should be normalized to the current year using a construction cost escalator such as the Handy Whitman Index. The Company used this method (booked costs escalated to the current year using the Handy Whitman Index) in the previous electric rate case. Ironically, the costing method that the OAG recommends in the current case is the same method sharply criticized by the OAG in the Company's last rate case.

Given the lack of availability of booked costs, using costs from actual distribution construction Work Orders was the most accurate source of distribution cost data for use in the current Minimum System and Zero Intercept studies.

h. Sufficiency of Historic Cost Data

Q. WAS THE COMPANY'S ANALYSIS SUPPORTED BY A SUFFICIENT LEVEL OF COST DATA?

A. Yes. The Company's analysis relied on cost data from the last five and a half years. The Work Orders included were completed between January 1, 2010 and May 31, 2015. As noted in Ms. Bloch's Rebuttal Testimony, these years represent the most current cost information and therefore are the most reflective of current costs to install particular pieces of equipment. The Company's Distribution Engineering group's filtering process provided nearly

1,900 Work Orders from which accurate cost estimates of unit costs for each equipment configuration could be obtained. For a given property unit, the equipment configurations for which unit cost data were developed represented at least 90 percent of the conductor footage or transformer units installed on the Company's distribution system.

That said, the Company agrees with Department witness Mr. Zajicek that including additional Work Orders from 2007 to 2009 would improve the study. However, the process of completing the original Minimum System and Zero Intercept studies filed in direct testimony took nearly four months of dedicated effort by distribution engineering and regulatory analysis staff, and there was insufficient time to include the required analysis in rebuttal testimony. After filtering the 2007-2009 Work Orders to only include those with one property unit and a single material configuration, an estimated 300-400 additional Work Orders could be added to the analysis.

i. *Sufficiency of Observation Per Regression*

Q. OAG WITNESS MR. NELSON HIGHLIGHTS THAT ONE OF THE COMPANY'S REGRESSIONS WAS BASED ON SIX OBSERVATIONS. IS THE REGRESSION VALID?

A. Yes. The six observations that Mr. Nelson refers to are the six underground secondary material configurations that make up 91 percent (nearly 2,000 miles) of all underground secondary conductor on the Company's system. The regression uses the actual cost data from nearly 200 Work Orders for these six configurations with nearly 17 miles of underground secondary conductor installed. The 200 Work Orders are a more than adequate sample for the regression in question.

j. Multicollinearity

Q. HOW DO YOU RESPOND TO MR. NELSON'S ASSERTIONS THAT THE COMPANY'S REGRESSION IS MIS-SPECIFIED, AND THAT THERE IS A PROBLEM WITH MULTICOLLINEARITY?

A. As described on page 92 of the NARUC manual, the Company performed Ordinary Least Squares Regression regressing "Load Carrying Capacity" as the independent variable (x axis) on the dependent variable "Installed Cost per Unit" (y axis).

"Multicollinearity" refers to a situation where there is a significant relationship between two or more independent variables that are included in the regression model to predict the value of the dependent variable. Multicollinearity makes it difficult to determine which independent variable has more impact on the dependent variable. Since the only independent variable in the OLS regression is load carrying capacity, multicollinearity cannot be an issue.

k. Ordinary Least Squares Assumptions

Q. DID THE COMPANY VIOLATE ANY ASSUMPTIONS REQUIRED FOR ORDINARY LEAST SQUARES (OLS) REGRESSION MODELS?

A. No. The Company provides the Gauss Markov assumptions for Ordinary Least Squares Regression in layman's terms in response to the OAG's IR No. 714, included as Schedule 3 to my Rebuttal Testimony. The Company's response to Department IR No. 715, included as Schedule 4 to my Rebuttal Testimony, shows the relevant statistics proving that the assumptions of the Ordinary Least Squares models are met.

Mr. Nelson states on page 55 of his Direct Testimony that the Company did not respond to his request for information on this topic. The Company in fact provided full responses in OAG IRs Nos. 714 and 715.

l. The Company Adjusted for the Load Carrying Capacity of the Minimum System.

Q. DID THE COMPANY MAKE A DEMAND ADJUSTMENT TO ACCOUNT FOR THE LOAD CARRYING CAPACITY OF THE MINIMUM-SIZED DISTRIBUTION SYSTEM IN ITS ANALYSIS?

A. Yes. As mentioned on page 30 of my Direct Testimony, the Company assumed the minimum-sized distribution system has a load carrying capacity of 1.5 kW per customer. This is the same assumption that was made in prior rate cases.

Additionally, the Company's response to XLI IR No. 18, included as Schedule 5 to my Rebuttal Testimony, provides the rationale for the 1.5 kW adjustment. The response also provides an explanation of how this adjustment is captured in the allocation factors for distribution plant investment.

m. Source of Costs Used in Minimum System and Zero Intercept Studies

Q. DID THE COMPANY USE BOOKED COSTS AS OPPOSED TO CURRENT COSTS IN ITS MINIMUM SYSTEM AND ZERO INTERCEPT STUDIES?

A. No. The data sources for the studies are described on pages 87-97 of Ms. Bloch's Direct Testimony and pages 7-12 of her Rebuttal Testimony. In short, the Company analyzed the costs of Work Orders that were completed between 2010 and May of 2015. As such, the costs included in the analysis are those that were recorded at the time each Work Order was closed, reflecting labor and material costs at that time.

Q. To account for the timing differences of when the Work Orders were closed, Department witness Mr. Zajicek suggests that the Company apply the Handy Whitman Index to normalize the costs to the current year. Would this improve the accuracy of the study results?

A. Yes. Although inflation was low throughout this time period, applying the Handy Whitman Index to each year's data would marginally improve the accuracy of the studies. The table below shows a comparison of study results with and without the Handy Whitman Index applied

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Table 1
Percent of Distribution Plant Investment Classified as Customer-Related
Zero Intercept Method versus the Minimum System Method
With and Without the Handy Whitman Adjustment Applied

Property Unit	% of Costs Classified as Customer-Related			
	Zero Intercept Method		Minimum System Method	
Property Unit	Without Handy Whitman Adjustment	With Handy Whitman Adjustment	Without Handy Whitman Adjustment	With Handy Whitman Adjustment
Overhead Primary	53.1%	51.5%	62.2%	61.8%
Overhead Secondary	63.9%	72.7%	100%	100%
Overhead Transformers	72.5%	76.9%	78.5%	80.6%
Underground Primary	67.7%	64.6%	65.5%	68.8%
Underground Secondary	64.3%	63.6%	94.9%	94.4%
Underground Transformers	87.3%	87.7%	56.6%	56.3%

n. Unit Cost for Underground Transformers

Q. SHOULD THERE BE A CONCERN THAT THE ZERO INTERCEPT UNIT COST FOR UNDERGROUND TRANSFORMERS WAS HIGHER THAN THE MINIMUM-SIZED TRANSFORMER?

A. No. Page 91 of the NARUC manual makes the following statement:

> Comparative studies between the minimum-size and other methods show that it ***generally*** produces a larger customer component than the zero intercept method . . .

The regression result for underground transformers is based on costs from over 200 Work Orders. As shown in the Company's response to OAG IR No. 715 (Schedule 4), the adjusted R^2 for this regression was 84.1 percent with an F-statistics significance level of 0.0000433. For the results of the regression model to be significant, the F-statistic significance level should be less than or equal to .05. The observed result simply reflects the variability in the unit cost data.

2. The D10S Capacity Allocator

Q. IN THE COMMISSION'S ORDER IN THE COMPANY'S LAST RATE CASE, THE COMMISSION ENCOURAGED THE COMPANY TO WORK WITH MISO AND OTHER PARTIES TO RECALCULATE THE D10S CAPACITY ALLOCATOR FOR PURPOSES OF COMPARISON TO THE COMPANY'S PEAK. DID THE COMPANY COMPLY WITH THAT ORDER?

A. Yes. As shown in the Company's February 24, 2016 Errata filing in the present docket, the Company used the peak hour for Local Resource Zone 1 for the 2015-2016 Planning Year, which was July 14, 2015 16:00 EST or 3:00 PM CST. Since the Planning Year 2016-2017 Loss of Load Expectations

(LOLE) Study was not yet available, the D10S allocator was calculated using forecasted class loads for that specific hour.

Q. Since filing direct testimony, has the Company reconsidered using the MISO peak hour to calculate the D10S capacity allocator?

A. Yes. The Company has conducted additional research and determined that basing the D10S allocator on the Midcontinent Independent System Operation ("MISO") peak hour does not accurately reflect what causes the Company to incur additional capacity costs. Also, the Company's (and other MISO utilities) method to determine its peak day and hour is done independently of MISO's method to determine its peak day and hour. As I show later in my Rebuttal Testimony, using the published MISO peak hour from rate case to rate case could produce a D10S allocator that may show drastic unexplained changes over time depending on the hour that MISO specifies as the peak hour. Two of the most important characteristics of a class cost allocator are that it reflects cost causation and is relatively stable over time. These characteristics are not present using the MISO peak hour method.

Q. In order to reflect what causes the Company to incur additional production capacity, how should the D10S capacity allocator be calculated?

A. The Company's process for determining its need for additional production capacity is described in its "2016-2030 Upper Midwest Resource Plan" as follows:

> Forecasting our customers need for electricity is a key component of any resource plan, and provides the basis for determining the type and amount of resources that will be needed over the 15-year planning period. Determining this need starts with a forecast of our customers' peak demand for electricity. To that, we add a Reserve Margin to reflect our contribution to MISO's pool of generation that can respond to unexpected equipment outages.

The Company's response to ICI Group IR No. 4, included as Schedule 6 to my Rebuttal Testimony, provides additional detail:

> The 2016-2030 Resource Plan utilizes a Coincident Factor of 95 percent and a PRM of 7.1 percent. This factor is based on historic coincident demands, and the MISO PRM current at the time the plan was filed. For specific planning years, MISO provides the Coincident Factor for that period, and updates the PRM annually.

In other words, NSP's System peak demand is the primary indicator that determines the need for additional production capacity. To reflect this, the D10S capacity allocator should be calculated using forecasted class demands coincident with the peak hour for the NSP System.

Q. FOR THE PURPOSE OF DETERMINING EACH UTILITY'S PLANNING RESERVE MARGIN, DOES MISO SPECIFY THE PEAK HOUR THAT EACH UTILITY MUST PLAN FOR?

A. No. The MISO peak hour is determined after each utility's capacity requirement is determined. After each utility has provided their capacity requirement to MISO with the required adjustments, MISO enters this data into their proprietary software. The planning year peak load forecast and associated peak hour are available after all utilities' capacity requirements have been determined.

Q. WHAT IMPACT DOES THE SELECTION OF THE MISO PEAK HOUR HAVE ON THE D10S ALLOCATOR?

A. The selection of the MISO peak hours can cause significant swings in the D10S allocator. Let me start by looking at the impact that Xcel Energy has on MISO's actual peak load. Table 2 below shows the hour (column 1) and MW peak load (column 2) for MISO's Local Resource Zone 1 (LRZ-1) for each of the years 2013-2015. The table also shows Xcel Energy's coincident peak load for the NSP System (column 3) and the State of Minnesota (column 4). As shown in columns 5 and 6, NSP's System and State of Minnesota load as a percent of the MISO's LRZ-1 load shows little variation from year to year.

Table 2
NSP Contribution to the Actual MISO LRZ-1 Peak

[1]	[2]	[3]	[4]	[5] = [3] / [2]	[6] = [4] / [2]
MISO Actual Peak Hour for LRZ-1	**MISO LRZ-1 Actual MW Peak**	**Actual Coincident NSP System MW**	**Actual Coincident State of MN Actual MW**	**NSP System MW as a % of MISO LRZ-1 Peak**	**NSP State of MN MW as a % of MISO LRZ-1 Peak**
Aug 26, 2013 @ 2PM	17,903	9,281	7,086	51.84%	39.58%
Jul 21, 2014 @ 3PM	17,019	8,819	6,624	51.82%	38.92%
Aug 14, 2015 @ 3PM	16,935	8,527	6,320	50.35%	37.32%

In contrast, Table 3 below shows the forecasted hour (column 1) and Forecast MW peak load (column 2) for MISO's Local Resource Zone 1 (LRZ-1) for each of the years 2013 - 2016. The table also shows Xcel Energy's forecasted coincident peak load for the NSP System (column 3) and the State of

Minnesota (column 4). As shown in columns 5 and 6, NSP's System and State of Minnesota load as a percent of the MISO's LRZ-1 peak load varies drastically from year to year.

Table 3
NSP Contribution to the Forecast MISO LRZ-1 Peak

[1]	[2]	[3]	[4]	[5] = [3] / [2]	[6] = [4] / [2]
MISO Forecast Peak Hour for LRZ-1	**MISO LRZ-1 Forecast MW Peak**	**Coincident NSP System Forecast MW**	**Coincident NSP State of MN Forecast MW**	**NSP System Fcst Peak as a % of MISO LRZ-1 Fcst Peak**	**NSP State of MN Fcst Peak as a % of MISO Fcst LRZ-1 Peak**
Jul 30, 2013 @ 4PM	17,085	6,815	4,563	39.89%	66.96%
Jul 15, 2014 @ 4PM	17,733	8,514	5,258	48.01%	61.76%
Jul 14, 2015 @ 3PM	17,974	NA	NA	NA	NA
Jul 12, 2016 @ 3PM	18,197	6,382	4,817	35.07%	75.48%

Tables 2 and 3 above show that although NSP's impact on the actual MISO peak is consistent from year to year, the Company's "apparent" impact on the forecasted MISO peak can vary by up to 13 percent. This demonstrates an obvious disconnect with how MISO determines its forecasted peak hour for the planning year, and how the Company develops its forecasted hourly loads. The implication is not that either method is incorrect, only that they are different.

Q. WHAT IMPACT DOES THE MISO PEAK HOUR HAVE ON THE D10S CLASS ALLOCATOR PERCENTAGES?

A. The selection of the MISO peak hour has a significant effect on the D10S capacity allocator. Looking at the last four years, the forecasted MISO LRZ-1 peak hour has been at 3:00 p.m. or 4:00 p.m. CST, falling midweek in mid to late July.

Schedule 7 to my Rebuttal Testimony shows the forecasted hourly class loads for each class for those hours in the 2016 test year. As shown in the table, if the forecasted time of the MISO LRZ-1 peak changes by only one hour on a given day (for example from 3:00 p.m. to 4:00 p.m., or vice versa), a given class's share of that peak can change by nearly four percent. More significantly, if the specified peak day changes, a given class's D10S allocator peak can change by up to 14 percent. To put that in perspective, a 10 percent increase in the D10S allocator for the residential class would increase the residential class revenue requirement by $89 million.

Q. DOES USING THE FORECASTED PEAK HOUR FOR THE NSP SYSTEM PROVIDE A STABLE D10S ALLOCATOR OVER TIME?

A. Yes. Table 4 below shows how the D10S allocator has changed over the last six rate cases using class loads that are coincident with the NSP System peak hour. As shown, the maximum change over time for the Residential and C&I Demand classes is less than five percent.

Table 4
D10S Production Capacity Allocator Based on Class Loads Coincident with the NSP System Peak Hour

Test Year	Allocator	MN	Resid	Commercial Non-Demand	C&I Demand	Lighting
2006	D10S			4.01%	58.44%	0.00%
2009	D10S	100.00%	37.94%	3.77%	58.29%	0.00%
2011	D10S	100.00%	34.83%	3.41%	61.76%	0.00%
2013	D10S	100.00%	35.31%	3.82%	60.87%	0.00%
2014	D10S	100.00%	34.85%	3.72%	61.42%	0.00%
2016	D10S	100.00%	39.63%	2.71%	57.65%	0.00%

3. The D60Sub Allocator

Q. XLI WITNESS MR. POLLOCK SUGGESTS A CHANGE TO THE CLASS CUSTOMER LOADS THAT ARE USED TO CALCULATE THE D60SUB ALLOCATOR. ARE HIS SUGGESTED CHANGES WARRANTED?

A. Yes. Mr. Pollock points out a correction that should be made to the allocator calculations. The D60Sub allocator is used to allocate the costs of distribution substations. As Mr. Pollock points out in his Direct Testimony, the costs of selected distribution substations are directly assigned to the customers that are served by these facilities. However, the loads for these customers are included when the D60Sub allocator is calculated. The D60Sub allocator is used to allocate costs of all other distribution substations. As Mr. Pollock correctly points out, the loads for customers served by distribution substations whose costs are directly assigned should be excluded from the loads used when calculating D60Sub allocator.

4. Loss Factors Used in the CCOSS

Q. WHAT ARE THE CHANGES THAT XLI WITNESS MR. POLLOCK SUGGESTS REGARDING THE LOSS FACTORS THAT ARE APPLIED TO CUSTOMERS' LOADS?

A. Loss factors are applied to customers' loads reflecting the fact that customers who are served at higher voltages are responsible for fewer losses that occur on the system than those served at lower voltages. As Mr. Pollock points out, the loss factors the Company applies are the same for each hour of the test year. He further notes that losses are a function of current and voltage, and current is highest during peak hours.

Q. WILL THE COMPANY CONDUCT A LOSS FACTOR STUDY TO REFLECT THIS VARIABILITY?

A. The Company is willing to report on loss factor study methodologies in its next rate case filing. The suggested analyses have not been conducted to date. The Company's treatment of losses is appropriate. Each respective rate group uses an hourly profile representing "typical" usage conditions, and the CCOSS indirectly accounts for periods of high current usage relative to other periods in a given month (as stated by Mr. Pollock). This method serves as a statistically valid method to estimate class usage for any period or hour of interest.

5. Direct Assigned Facilities No Longer Serving Customers

Q. MR. POLLOCK POINTS OUT THAT THERE ARE CERTAIN TRANSMISSION RADIAL LINE AND DISTRIBUTION SUBSTATIONS WHOSE COSTS ARE DIRECTLY ASSIGNED TO CUSTOMERS WHO ARE NO LONGER TAKING SERVICE. HE SUGGESTS THAT THE COSTS OF THESE FACILITIES BE ALLOCATED TO ALL CUSTOMERS. DO YOU AGREE?

A. Yes. Some of these facilities are in the Retirement Work in Progress ("RWIP") process and will no longer be on the Company's books. For those that remain, I agree that it is appropriate to allocate these costs to all customer classes.

6. Allocation of CIP CCRC Costs that are Recovered in Base Rates

Q. SHOULD CIP COSTS THAT ARE RECOVERED IN BASE RATES BE ALLOCATED USING AN E8760 ALLOCATOR THAT IS ADJUSTED TO EXCLUDE THE HOURLY ENERGY OF CUSTOMERS WHO ARE CIP EXEMPT?

A. Yes. Although the Company's CCOSS followed the method ordered by the Commission, the Company would support MCC witness Ms. Maini's argument that the E8760 allocator be adjusted to exclude energy provided to

Conservation Improvement Program ("CIP") exempt customers. We support this modification, since 63 percent of the impacts of CIP programs are energy-related, and doing so would cause the allocator to better reflect cost causation.

As ordered, CIP Conservation Cost Recovery Charge ("CCRC") costs are allocated on sales excluding sales to CIP exempt customers. At this time the Company does not have the hourly loads of CIP exempt customers needed to accurately calculate the suggested allocation factor. The Company can develop an allocator that closely approximates the suggested allocator by adjusting each class's hourly energy by the same respective percent of sales reductions realized by excluding sales to CIP exempt customers from each class.

7. Changes to the Allocation Methods for Costs Included in Rate Riders

Q. PLEASE SUMMARIZE THE CHANGES RECOMMENDED BY MS. MAINI TO ALLOCATE COSTS RECOVERED THROUGH THE CIP, RDF AND FUEL CLAUSE RIDERS.

A. Ms. Maini suggests the following changes to more accurately reflect cost causation:

- Renewable Development Fund ("RDF") costs should be allocated using a composite allocator that is 50 percent weighted on the D10S capacity allocator and 50 percent weighted on the E8760 energy allocator.
- Similar to Ms. Maini's suggestion for CIP CCRC costs, she recommends that CIP costs recovered through the rider should be allocated to class using the E8760 allocator adjusted to exclude energy provided to CIP exempt customers.
- Since MISO has assigned a preliminary capacity value of 50 percent to

solar projects, Ms. Maini recommends that costs of solar projects that are recovered through the fuel clause adjustment ("FCA") should be allocated using a composite allocator that is 50 percent weighted on the D10S capacity allocator and 50 percent weighted on the E8760 energy allocator.

Q. WHAT IS YOUR RESPONSE TO THESE RECOMMENDATIONS?

A. The Company feels these recommendations deserve further consideration. We believe that these recommendations exceed the scope of this proceeding, and that the appropriate venue for these discussions would be in the respective rider dockets.

III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In light of the August 16, 2016 Stipulation of Settlement, the Company recommends that the CCOSS filed with my Direct Testimony be factored down to meet the 2016 Settlement revenue requirement for revenue apportionment purposes. The Company-proposed Settlement-level revenue apportionment is discussed in Mr. Huso's Rebuttal Testimony. On a going forward basis, the Company also makes several recommendations to the proposed classification and allocation methods that more accurately reflect cost causation. While there are recommended changes to the classification and allocation methods, the methods used in the CCOSS filed with my Direct Testimony reflect past Commission orders.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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Xcel Energy

Docket No.:	E002/GR-15-826		
Response To:	Clean Energy Organizations	Information Request No.	19
Requestor:	Hudson Kingston, Samantha Williams		
Date Received:	August 17, 2016		

Question:

Reference Xcel Supplemental Response to CEO Information Request No. 1. With regard to the 2016 CCOSS model provided in the supplemental response to CEO Information Request No. 1, please provide a revised version of this spreadsheet model which reflects the stipulated amount for 2016 test year revenue requirements in the August 15, 2016 Stipulation of Settlement.

Response:

The Company does not intend, at this time, to develop a CCOSS which reflects the stipulated amount for the 2016 test year revenue requirements in the August 15, 2016 Stipulation of Settlement. However, for illustrative purposes, the following table provides the Company's class revenue requirements and proposed class revenue apportionment as filed and comparably at the Settlement revenue requirement. The Settlement level results by class were determined using the proportional factoring adjustment methodology that was discussed in the Direct Testimony of Company witness Mr. Steven V. Huso on page 11.

	Present	Proposed Cost / Revenue		
Class	**Revenue**	**Amount**	**Increase**	**Incr %**
TY 2016 Cost				
Residential	$1,079.70	$1,180.95	$101.25	9.38%
Non-Demand	$111.77	$115.04	$3.27	2.92%
C&I Demand	$1,815.26	$1,901.32	$86.06	4.74%
Lighting	$26.56	$30.17	$3.61	13.59%
Total	$3,033.28	$3,227.48	$194.19	6.40%
TY 2016 Cost at Settlement Level				
Residential	$1,079.70	$1,118.80	$39.10	3.62%
Non-Demand	$111.77	$113.03	$1.26	1.13%
C&I Demand	$1,815.26	$1,848.49	$33.23	1.83%
Lighting	$26.56	$27.96	$1.39	5.25%
Total	$3,033.28	$3,108.27	$74.99	2.47%
TY 2016 Proposed				
Residential	$1,079.70	$1,170.35	$90.66	8.40%
Non-Demand	$111.77	$116.35	$4.58	4.09%
C&I Demand	$1,815.26	$1,911.56	$96.30	5.31%
Lighting	$26.56	$29.22	$2.66	10.00%
Total	$3,033.28	$3,227.48	$194.19	6.40%
TY 2016 Proposed at Settlement Level				
Residential	$1,079.70	$1,114.71	$35.01	3.24%
Non-Demand	$111.77	$113.54	$1.77	1.58%
C&I Demand	$1,815.26	$1,852.44	$37.19	2.05%
Lighting	$26.56	$27.59	$1.03	3.86%
Total	$3,033.28	$3,108.27	$74.99	2.47%

Witness: Michael A. Peppin / Steven V. Huso
Preparer: Steven V. Huso
Title: Pricing Consultant
Department: Regulatory Analysis
Telephone: 612-330-2944
Date: August 30, 2016

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Xcel Energy
Docket No.: E002/GR-15-826
Response To: Office of Attorney General Information Request No. 706
Requestor: Ryan P. Barlow
Date Received: April 5, 2016

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Distribution System Planning.

Explain how Xcel plans its distribution system to minimize energy losses. If Xcel does not plan its distribution system to minimize energy losses, explain why not.

Response:

Minimizing energy losses is one of the key considerations that Xcel Energy takes into account in designing and operating the distribution system. Energy losses are factored into decisions about feeder lengths, standard conductor and cable sizes, distribution transformer specifications, and operating voltage. Xcel Energy also takes steps to minimize energy losses by reducing reactive power or VARs through the use of capacitor banks and by checking phase balancing during annual planning cycles.

Losses are defined as the product of the current squared and the impedance, so by minimizing the current or impedance the overall losses are also minimized.

In planning new feeders, Xcel Energy seeks to minimize the length of new distribution feeders to reduce energy losses. Shorter feeders limit the impedance of the line resulting in few energy loses. Energy loss considerations also factor into determining the best operating voltage levels for new feeders. This may include using higher voltages, typically 23.9 kV or 34.5 kV, for longer distances or converting existing smaller voltages, typically 4.16 kV, to a more suitable voltage level. By utilizing higher voltages, the same amount of power can be delivered at lower current limiting energy losses. However, sometimes it is beneficial to use lower voltages to match existing voltage of the surrounding system to avoid excess voltage transformations which lead to more losses.

When selecting standard sized conductors and cables, Xcel Energy utilizes ones that are best for the situation balancing load requirements, price, and losses. Typically, this involves selecting conductors or cables with lower impedances which lowers the losses and increased capability.

When evaluating new transformers, Xcel Energy uses standard specifications that are meant to keep losses at a minimum, among other things. Also, selecting the optimal size of transformer to meet load requirements ensures that no-load losses are minimized. No-load losses occur with every transformer but increase with the size of the unit, so using a larger size than what is needed to serve the load will result in more losses.

Another way that Xcel Energy minimizes energy losses is by reducing reactive power or VARs. Xcel Energy reduces VARs by strategically placing capacitor banks on its distribution feeders to locally provide this energy component that end use devices, like motors, require without it traveling from the centralized generation station. By reducing VARs, the overall current is also reduced, which in turn leads to fewer losses. Xcel Energy works to ensure that the process of switching the capacitor banks off and on corresponds with changes in load on the system. This further reduces energy loss by not over or under supporting the VAR needs at particular points in time.

Energy losses are also addressed by phase balancing during Distribution's annual planning cycle. When load is not properly balanced across the three phases in a distribution network, losses are increased as a result. Xcel Energy engineers monitor the distribution of single phase loads between all three phases to ensure they are balanced for each feeder in the system. If one phase is determined to be much higher than the other two, a balancing project is initiated to more closely match each of the feeder's phases to one another. This minimizes losses by decreasing the current on one phase.

Witness:	Kelly A. Bloch
Preparer:	Chris J. Punt
Title:	Senior Engineer
Department:	System Planning MN
Telephone:	763-493-1849
Date:	April 12, 2016

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Xcel Energy			
Docket No.:	E002/GR-15-826		
Response To:	Office of Attorney General	Information Request No.	714
Requestor:	Ian Dobson		
Date Received:	April 27, 2016		

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Zero Intercept Regression.

Provide the statistical/mathematical assumptions that Xcel is making when conducting an ordinary least squares regression. If these assumptions differ from the standard ordinary least squares assumptions, such as those found in Gujarati and Porter (2009) or other econometrics textbooks, explain why it is reasonable to vary from the standard assumptions. Where applicable, provide your answer in a live Excel spreadsheet with all links and formulas intact.

Response:

As described on pages 92 – 94 of the National Association of Regulatory Utility Commissioners (NARUC) manual, the Company performed Ordinary Least Squares Regression regressing "Cost per Unit" (for each type of distribution equipment) as the dependent variable (y axis) on the variable "Load Carrying Capacity" as the independent variable (x axis). The point where the regression line crosses the Y intercept is the theoretical "zero load" cost per unit.

The calculation is represented by the following equation:

$$y = B_0 + B_1x + e$$

Where:

y = Dependent variable = Cost per Unit

x = Independent variable = Load Carrying Capacity

e = Random Error Component

B_0 = y intercept line or the Unit Cost at the Theoretical "Zero Load"

B_1 = Slope of the Regression line

The Ordinary Least Squares regression line is one where:

- The sum of the errors represented by "e" in the above formula equals Zero and the sum of the squared errors (SSE) is smaller than any other possible regression line.
- The variance of the error terms is constant for all values of the independent variable.
- The probability distribution of the error terms is normal.
- If the assumption of linearity is met, there should be no relationship between the standardized predicted values of the dependent variable and the standardized residuals.

These assumptions are the same as standard Ordinary Least Squares assumptions.

Witness:	Michael A. Peppin
Preparer:	Michael A. Peppin
Title:	Principal Pricing Analyst
Department:	Regulatory Analysis
Telephone:	612-337-2317
Date:	May 9, 2016

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Xcel Energy
Docket No.: E002/GR-15-826
Response To: Office of Attorney General Information Request No. 715
Requestor: Ian Dobson
Date Received: April 27, 2016

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Zero Intercept Regressions.

Provide any and all diagnostic analysis conducted to check the ordinary least squares assumptions for each and every regression. Where applicable, provide your answer in a live Excel spreadsheet with all links and formulas intact.

Response:

Please see Attachment A to this response. Attachment A, provided in live Excel spreadsheet format, includes a separate tab with relevant statistics for each regression model as shown in Attachments H to M of Schedule 11 to Company witness Mr. Michael Peppin's Direct Testimony.

The data for replicating the regression models is shown in columns A and B for each spreadsheet tab of Attachment A to this response.

The relevant output for each regression model is also shown is Attachment A. Following are some useful statistics for assessing utility of each regression model.

- **R^2 and Adjusted R^2**: Also known as the "Coefficient of Determination". This statistic tells the analyst the degree to which having information on the independent variable is useful for predicting the value of the dependent variable. A value of 1 means the independent variable perfectly predicts the value of the dependent variable. It can also be interpreted as the percent of variability in the dependent variability that is explained by the independent variable. The "Adjusted R^2" statistic attempts to correct the R^2 statistic by accounting for the number of independent variables that are in the model.

- **F statistic and its associated significance level**: The F statistic also tests how well the regression model fits the data. The minimum criteria should be a F statistic significance level less than or equal to .05.
- **Scatterplot of the standardized residuals Vs the predicted value of y**: Tests for the appropriateness of a linear model and the assumption of equal variance of the error term. For model assumptions to hold true, there should be no discernable pattern in the scatter plot.

The table below summarizes the results of the regression models.

Property Unit	R^2	Adjusted R^2	F Statistic	F Statistic Sig. Level	Scatterplot Pattern?
Overhead Primary	.912	.906	144.74	.00000001	None
Overhead Secondary	.694	.672	31.689	.0000622	None
Overhead Transformers	.869	.853	53.034	.0000853	None
Underground Primary	.922	.910	82.200	.0000407	None
Underground Secondary	.794	.742	15.410	.01717	None
Underground Transformers	.857	.841	54.019	.0000433	None

On all of the above measures, all the regression models are useful for estimating a zero intercept for all property units.

Witness: Michael A. Peppin
Preparer: Michael A. Peppin
Title: Principal Pricing Analyst
Department: Regulatory Analysis
Telephone: 612-337-2317
Date: May 9, 2016

OHPLoad	OHPCost
150	13.24
200	8.12
140	7.45
140	7.45
165	6.28
1680	23.61
600	12.00
1695	25.95
885	13.40
450	17.88
420	10.06
420	10.06
780	17.32
1680	22.55
2295	30.88
2295	33.94

Model Summaryb

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics				
					R Square Change	F Change	df1	df2	Sig. F Change
1	.955	.912	.906	2.6927203	.912	144.739	1	14	.00000001

ANOVAb

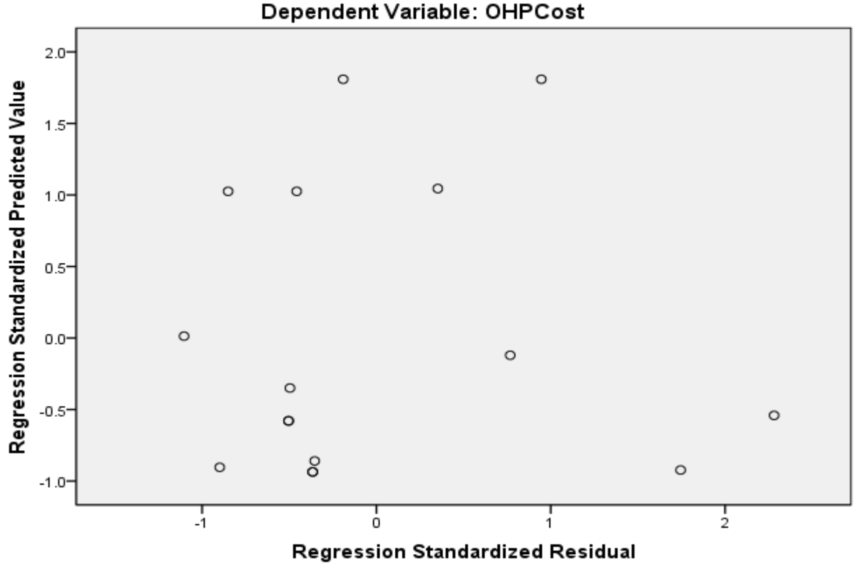
Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	1049.467	1	1049.467	144.739	.00000001
	Residual	101.510	14	7.251		
	Total	1150.977	15			

Coefficientsa

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.	95.0% Confidence Interval for B	
		B	Std. Error	Beta			Lower Bound	Upper Bound
1	(Constant)	6.943	1.026		6.766	.00000908	4.742	9.144
	OHPLoad	.011	.001	.955	12.031	.00000001	.009	.013

Scatterplot

Dependent Variable: OHPCost



Northern States Power Company
Regression Statistics for Overhead Secondary

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OHSLoad	OHSCost
200	3.81
150	3.26
260	4.34
140	3.38
140	3.38
185	3.41
245	3.72
205	4.44
90	3.50
205	4.44
165	3.92
300	4.90
150	3.28
295	4.86
90	3.38
265	5.13

Model Summary

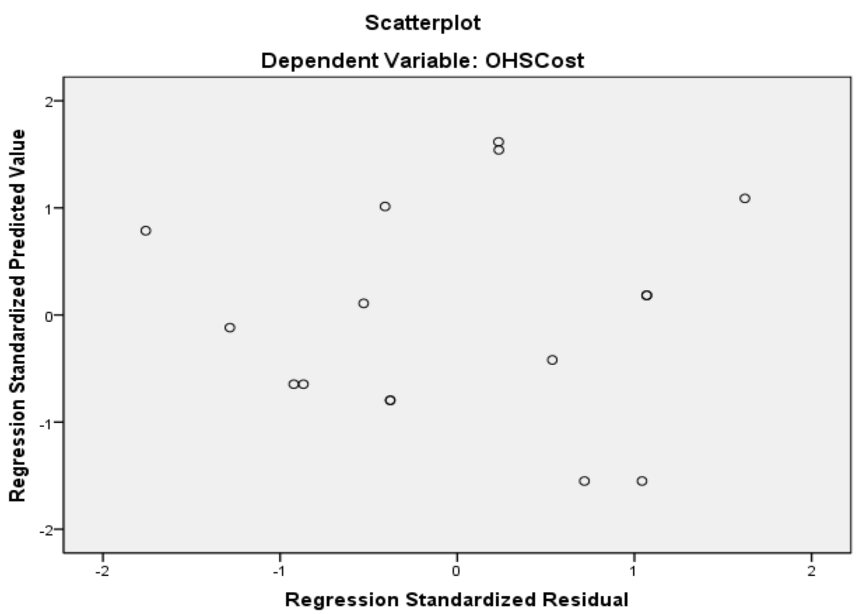
Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics				
					R Square Change	F Change	df1	df2	Sig. F Change
1	.833	.694	.672	.3690398	.694	31.689	1	14	.0000622

ANOVAb

Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	4.316	1	4.316	31.689	.0000622
	Residual	1.907	14	.136		
	Total	6.222	15			

Coefficientsa

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.	95.0% Confidence Interval for B	
		B	Std. Error	Beta			Lower Bound	Upper Bound
1	(Constant)	2.387	.292		8.174	.0000011	1.761	3.013
	OHSLoad	.008	.001	.833	5.629	.0000622	.005	.011



Northern States Power Company
Regression Statistics for Overhead Transformers

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OHTransLoad	OHTransCost
25	2212
10	1915.36
37.5	2732
15	2012
50	3307
75	5171
150	6756
112	5808
45	4697
100	4566

Model Summaryb

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics				
					R Square Change	F Change	df1	df2	Sig. F Change
1	.932	.869	.853	659.63396	.869	53.034	1	8	.0000853

ANOVAb

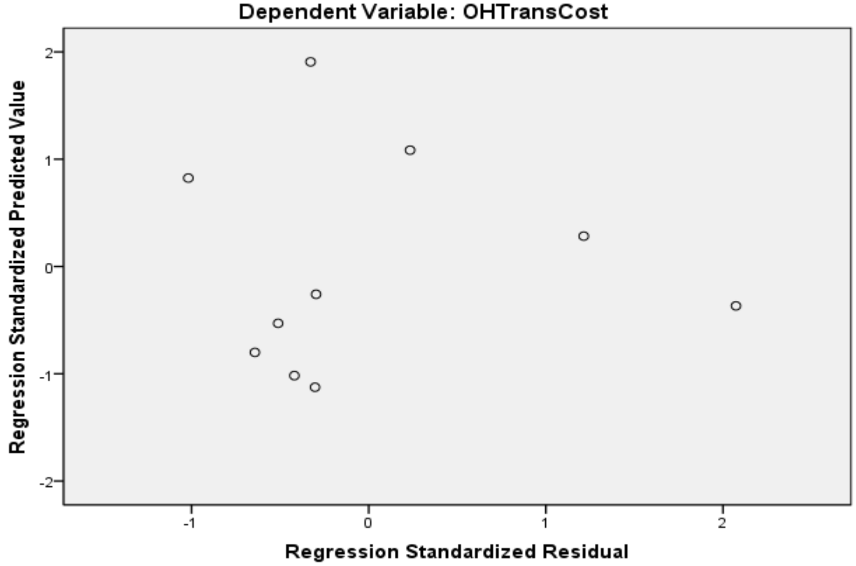
Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	23075916.911	1	23075916.911	53.034	.000085
	Residual	3480935.733	8	435116.967		
	Total	26556852.645	9			

Coefficientsa

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.	95.0% Confidence Interval for B	
		B	Std. Error	Beta			Lower Bound	Upper Bound
1	(Constant)	1768.398	361.402		4.893	.001204	935.004	2601.792
	OHTransLoad	34.693	4.764	.932	7.282	.000085	23.707	45.679

Scatterplot

Dependent Variable: OHTransCost



Northern States Power Company
Regression Statistics for Underground Primary

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UGPLoad	UGPCost
275	14.95
225	12.05
645	21.58
1890	38.08
510	20.62
2190	32.19
1545	31.78
1830	34.77
2340	41.66

Model Summaryb

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics				
					R Square Change	F Change	df1	df2	Sig. F Change
1	.960	.922	.910	3.1483993	.922	82.200	1	7	.0000407

ANOVAb

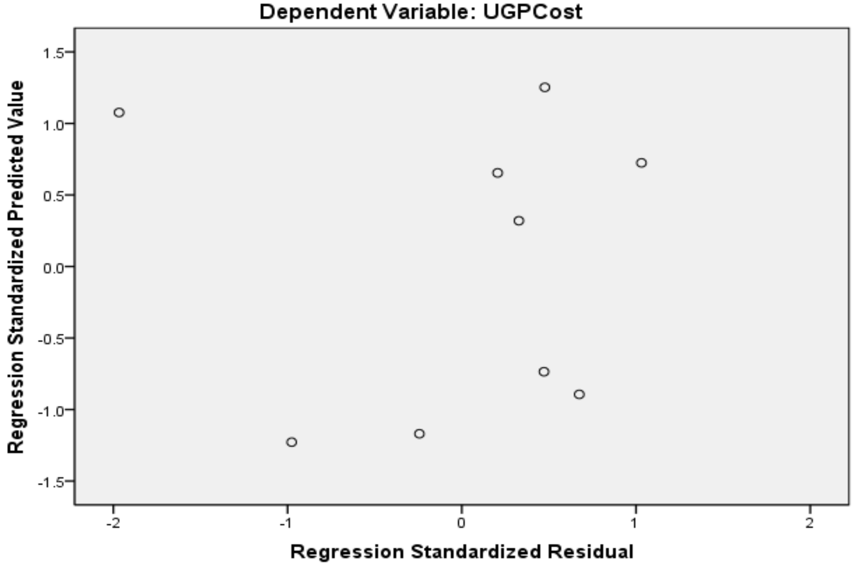
Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	814.805	1	814.805	82.200	.000041
	Residual	69.387	7	9.912		
	Total	884.192	8			

Coefficientsa

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.	95.0% Confidence Interval for B	
		B	Std. Error	Beta			Lower Bound	Upper Bound
1	(Constant)	12.461	1.965		6.342	.000388	7.815	17.107
	UGPLoad	.012	.001	.960	9.066	.000041	.009	.015

Scatterplot

Dependent Variable: UGPCost



Northern States Power Company
Regression Statistics for Underground Secondary

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Attachment A - Page 5 of 6

UGSLoad	UGSCost
90	6.07
340	9.01
280	10.58
220	7.17
140	6.59
450	10.82

Model Summaryb

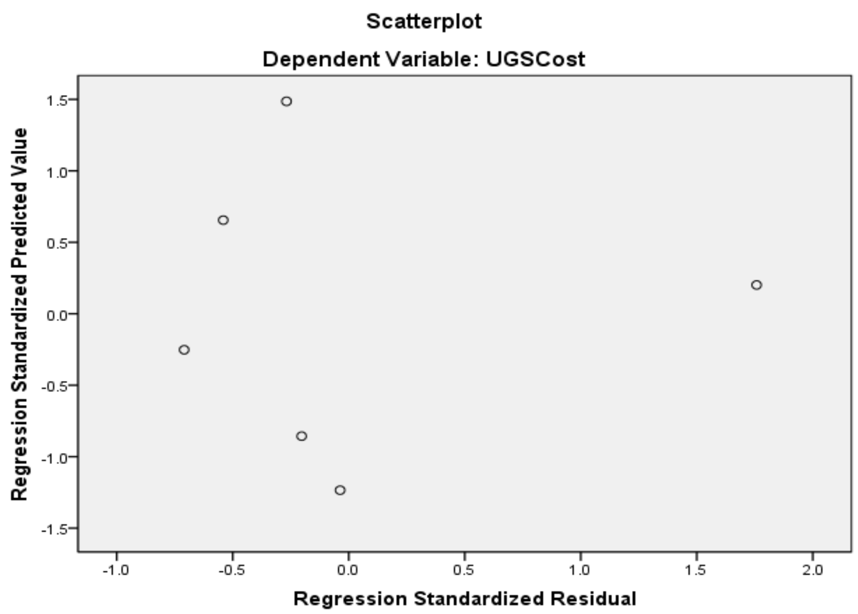
Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics				
					R Square Change	F Change	df1	df2	Sig. F Change
1	.891	.794	.742	1.04496	.794	15.410	1	4	.01717

ANOVAb

Model		Squares	df	Mean Square	F	Sig.
1	Regression	16.827	1	16.827	15.410	.01717
	Residual	4.368	4	1.092		
	Total	21.195	5			

Coefficientsa

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.	95.0% Confidence Interval for B	
		B	Std. Error	Beta			Lower Bound	Upper Bound
1	(Constant)	4.861	.991		4.904	.00802	2.109	7.613
	UGSLoad	.014	.004	.891	3.926	.01717	.004	.024



UGTransLoad	UGTransCost
50	3093.00
25	2152.79
37.5	3770.00
150	7630.00
300	9545.00
75	7166.00
500	10819.00
15	2481.00
112	7216.96
225	8539.39
750	14982.00

Model Summaryb

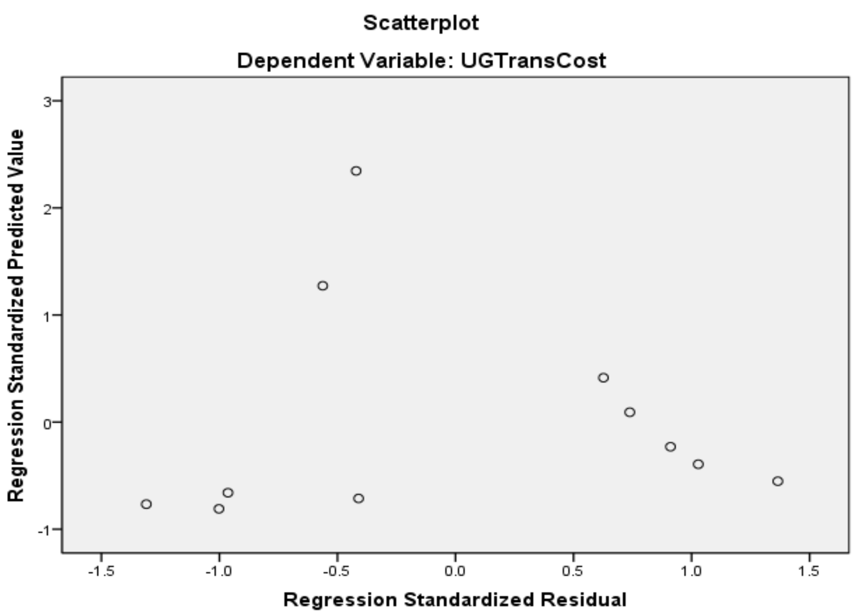
Model	R	R Square	Adjusted R Square	Std. Error of the Estimate	Change Statistics				
					R Square Change	F Change	df1	df2	Sig. F Change
1	.926	.857	.841	1579.47525	.857	54.019	1	9	.0000433

ANOVAb

Model		Sum of Squares	df	Mean Square	F	Sig.
1	Regression	134762841.17	1	134762841.168	54.019	.00004
	Residual	22452678.68	9	2494742.076		
	Total	157215519.85	10			

Coefficientsa

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.	95.0% Confidence Interval for B	
		B	Std. Error	Beta			Lower Bound	Upper Bound
1	(Constant)	3827.435	646.038		5.924	.00022	2365.996	5288.875
	UGTransLoad	15.759	2.144	.926	7.350	.00004	10.909	20.610



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Xcel Energy
Docket No.: E002/GR-15-826
Response To: Xcel Large Industrials Information Request No. 18
Requestor: Andrew Moratzka, Sarah Johnson Phillips, Emma J. Fazio
Date Received: January 5, 2016

Question:
Reference: Peppin Direct, Sch. 11, pg. 9:

Please provide the following:

a. Studies and analysis that document the 1.5 kW per customer load carrying capacity of the minimum system design.

b. Workpapers showing how the 1.5 kW per customer adjustment was applied to the distribution capacity cost allocation factors.

Response:

a. The 1.5 kW per customer load carrying capacity is a value that has been used in previous minimum system studies conducted by the Company. The 1.5 kW value is an approximation of the load of a small residential customer with typical electrical appliances at minimal usage levels. The residential customer class was chosen as it represents a relatively small, single phase load size. Multiple examples of combinations of modern residential appliances that operate at a load of 1.5 kW are provided on page 92 of Company witness Ms. Kelly A. Bloch's Direct Testimony, lines 12-14.

   Additionally, the Company's current Distribution standard design for a new small house or townhouse indicates an estimated peak load of 6 kW, including the air conditioning load. It is reasonable to estimate that neglecting the use of air conditioning and assuming minimal use of other household appliances will result in approximately 1.5 kW of load. As noted in the response to part b, below, when applying this minimum load estimate to the distribution capacity cost allocation factors, the Company adjusts the minimum load to account for each class's load diversity.

b. Please see the non-public live version of the Class Cost of Service Study model provided on CD with the Company's application. In the spreadsheet tab labeled “Alloc-Dist-Cap”, the following calculations were made to apply the 1.5 kW per customer adjustment:

- In column 5, each class’s class coincident load (shown in column 2), is divided by each class’s non coincident load (shown in column 1), to reflect the load diversity of each class. This result is then multiplied by the 1.5 kW load carrying capacity of the minimum system to provide the minimum kW per customer as shown in column 5.
- The minimum kW per customer (column 5) is multiplied by the number of customers in column 6 to provide the total minimum system load for each class in column 7.
- The minimum system loads for each class in column 7, are subtracted from the loads used for the following allocators for capacity-related distribution costs:
    - “D61PS” allocator shown in column 8: Used to allocate the capacity-related costs of primary distribution lines and primary transformers.
    - “D62SecL” allocator shown in column 12: Used to allocate the capacity-related costs of secondary distribution lines and secondary transformers.
    - “D62NLL” allocator shown in column 13: Used to allocate the capacity-related costs of services.

For more detail on the derivation and rationale for all class cost allocators, please see Schedule 2 of Company witness Mr. Michael A. Peppin’s Direct Testimony, “Guide to the Electric Class Cost of Service Study.”

Witness:	Michael Peppin
Preparer:	Brian Monson / Michael Peppin
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Telephone:	763-493-1811 / 612-337-2317
Date:	January 12, 2016

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Xcel Energy			
Docket No.:	E-002/GR-15-826		
Response To:	ICI Group and U.S. Energy	Information Request No.	4
Requestor:	Peder A. Larson		
Date Received:	March 24, 2016		

Question:

Reference Peppin Direct Testimony page 21 regarding **Allocator D10S:**
Does the company plan its power production capacity to supply the 7,253 MW as shown for the NSP peak hour or the 6,307 MW as shown for the MISO peak hour?

Response:

For purposes of planning, the Company does not use either value. The data for Table 7, Page 21, of Company witness Mr. Michael A. Peppin's Direct Testimony[1] represents forecast data for the 2015-2016 MISO planning year for Local Resource Zone 1, specific to July 14, 2015 3:00 PM CST.

For planning purposes, peak demand is forecasted on a monthly basis for the NSP system, not coincident with the MISO peak. The peak month is July, and the system includes five state jurisdictions.

To determine the planning obligation for the system, the peak demand is adjusted to be coincident with MISO peak, and the required Planning Reserve Margin (PRM) is added. The 2016-2030 Resource Plan utilizes a Coincident Factor of 95 percent and a PRM of 7.1 percent. This factor is based on historic coincident demands, and the MISO PRM current at the time the plan was filed. For specific planning years, MISO provides the Coincident Factor for that period, and updates the PRM annually.

Witness:	Mike Peppin
Preparer:	Mary Morrison
Title:	Resource Planning Analyst
Department:	Resource Planning and Bidding
Telephone:	612.330.5862
Date:	April 4, 2016

[1] As filed in the Company's ERRATA to the Application for Authority to Increase Rates for Electric Service on February 24, 2016 in Docket No. E002/GR-15-826.

Forecast 2016 Class MW Loads and D10S Allocator Percents for Likely Peak Hours in July

		Forecast Test Year 2016 Hourly Loads (MW)					D10S Allocator Percents				
Date / Time	Weekday	Resid	Comm Non Demand	C&I Demand	Ltg	MN	Resid	Comm Non Demand	C&I Demand	Ltg	MN
07/12/2016 03:00 PM	Tuesday	1,252	172	3,393	0	4,817	26.00%	3.58%	70.42%	0.00%	100.00%
07/12/2016 04:00 PM	Tuesday	1,425	145	3,226	0	4,795	29.72%	3.02%	67.27%	0.00%	100.00%
07/13/2016 03:00 PM	Wednesday	1,495	188	3,526	0	5,210	28.70%	3.61%	67.69%	0.00%	100.00%
07/13/2016 04:00 PM	Wednesday	1,681	158	3,367	0	5,207	32.29%	3.04%	64.67%	0.00%	100.00%
07/14/2016 03:00 PM	Thursday	2,241	215	3,851	0	6,307	35.53%	3.41%	61.06%	0.00%	100.00%
07/14/2016 04:00 PM	Thursday	2,415	182	3,663	0	6,260	38.58%	2.90%	58.52%	0.00%	100.00%
07/19/2016 03:00 PM	Tuesday	2,159	214	3,830	0	6,203	34.81%	3.46%	61.74%	0.00%	100.00%
07/19/2016 04:00 PM	Tuesday	2,339	181	3,639	0	6,159	37.97%	2.94%	59.08%	0.00%	100.00%
07/20/2016 03:00 PM	Wednesday	1,496	189	3,528	0	5,213	28.70%	3.62%	67.68%	0.00%	100.00%
07/20/2016 04:00 PM	Wednesday	1,685	159	3,371	0	5,214	32.32%	3.04%	64.64%	0.00%	100.00%
07/21/2016 03:00 PM	Thursday	1,212	168	3,337	0	4,717	25.69%	3.56%	70.75%	0.00%	100.00%
07/21/2016 04:00 PM	Thursday	1,383	141	3,180	0	4,704	29.41%	2.99%	67.60%	0.00%	100.00%
07/26/2016 03:00 PM	Tuesday	2,288	220	3,892	0	6,400	35.75%	3.43%	60.82%	0.00%	100.00%
07/26/2016 04:00 PM	Tuesday	2,471	186	3,699	0	6,356	38.88%	2.93%	58.19%	0.00%	100.00%
07/27/2016 03:00 PM	Wednesday	2,587	231	4,190	0	7,008	36.92%	3.30%	59.78%	0.00%	100.00%
07/27/2016 04:00 PM	Wednesday	2,784	196	4,026	0	7,006	39.74%	2.80%	57.46%	0.00%	100.00%
07/28/2016 03:00 PM	Thursday	2,693	232	4,373	0	7,297	36.91%	3.17%	59.92%	0.00%	100.00%
07/28/2016 04:00 PM	Thursday	2,874	197	4,182	0	7,253	39.63%	2.71%	57.65%	0.00%	100.00%