BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS

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FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

121 Seventh Place East Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Application of	**)**	
Northern States Power Company, a	**)**	**MPUC DOCKET NO. E-002/GR-13-868**
Minnesota Corporation, for Authority to	**)**	**OAH DOCKET NO. 68-2500-31182**
Increase Rates for Electric	**)**	
Service in Minnesota	**)**	

INITIAL BRIEF OF THE MINNESOTA CHAMBER OF COMMERCE

September 23, 2013

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Table of Contents

I. INTRODUCTION.

Northern States Power Company ("Xcel" or the "Company") initiated this case for increased rates and restructured rate design on November 4, 2013, seeking to increase base rates by $192.7 million, or 6.9% (on total, overall rates) effective January 3, 2014, and $98.5 million effective January 2015. The Minnesota Chamber of Commerce ("Chamber") initially contested several issues. Some of these issues were resolved or settled before briefing.

The issues that remain contested between Xcel, the Chamber, and/or at least one other party include Revenue Requirement, Class Cost of Service Study selection, Revenue Apportionment, Rate Design and Miscellaneous other issues. The issues that have been resolved through testimony or settlement are identified in the Issues Summary Document if not addressed herein.

Based on the record in this case, as well as the authority cited herein, the Chamber's positions on the disputed issues are appropriate and supported by Minnesota law.

II. BURDEN OF PROOF.

In Minnesota, a utility seeking a rate change carries the burden of proof to show that its requested change is just and reasonable.[1] Importantly, Minnesota law requires "[a]ny doubt as to reasonableness [to] be resolved in favor of the consumer."[2] The Minnesota Supreme Court has made it clear that a utility can only satisfy its burden of proof through a demonstration of a fair preponderance of the evidence.[3]

When determining whether costs should be borne by ratepayers or the utility's shareholders, the Minnesota Public Utilities Commission ("Commission") "acts in both a quasi-

[1] Minn. Stat. § 216B.16, Subd. 4 (2014).
[2] Minn. Stat. § 216B.03 (2014).
[3] In re N. States Power Co., 416 N.W.2d 719, 722 (Minn. 1987).

judicial and partially legislative capacity."[4] In order to allow the Commission to make a determination as to whether certain costs should be borne by ratepayers, the utility does not meet "its burden of demonstrating that it is just and reasonable that the ratepayers bear the costs of [certain] expenses" by "merely showing that it has incurred, or may hypothetically incur, [those] expenses."[5] Instead, when considering such costs and expenses, the Commission "may draw its own inferences and arrive at its own conclusions."[6] Indeed, this is precisely what the Commission must weigh in this case, where a utility has and is incurring costs, but it would not be prudent to pass these costs on to ratepayers.

III. CONTESTED ISSUES

While some issues remaining deal with whether Xcel is entitled to recovery at all, some issues deal with timing of recovery from ratepayers. The record demonstrates that now is not the time to push costs on ratepayers if they do not have to be incurred. Certainly, current ratepayers should not be paying for costs that only benefit future ratepayers.

Furthermore, impacts we are now seeing in Minnesota's economy are demonstrating that class allocation and rate design as proposed by Xcel or the Department is not appropriate. Xcel's ratepayers have seen many increases over the past several years and are seeing the negative results that are inevitable when increases are disproportionately pushed on businesses. Xcel's system has unnecessarily high C&I rates compared to other utilities in Minnesota, in the region and on a national basis.[7] Xcel has been observing the struggles of its industrial customers and seeing the results of this concern through their corporate customers having weak demand and

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[4] Id.
[5] Id. at 723.
[6] Id.
[7] Ex. 343, Maini Direct at 31:15-22.

moving operations outside of Xcel's service territory.[8] These increases are contributing to closing of Minnesota's largest energy consumers and employers, including Ford and Verso; contributing to its largest ratepayers, including the University of Minnesota, seeking alternative supplies of electricity; and contributing to the need of special rates for those who remain.[9] The record throughout includes these undisputed concerns and impacts. Now is not the time to unnecessarily push rates on these employers.

A. REVENUE REQUIREMENT ISSUES

1. Prairie Island

(a) Cancelled EPU

The Chamber recommended the Company be allowed to recover costs over the period of the remaining life of the facility without earning their Return on Equity.[10] The Company accepted the proposal by the Department to recover the costs over the remaining life of the facility with a carrying cost of 2.24%.[11] The Chamber does not object to this proposal.[12]

2. Monticello EPU

(a) Used and Useful

Xcel initiated a combined project for their Monticello nuclear generating facility to complete Life Cycle Management ("LCM") and Extended Power Uprate ("EPU") concurrently. In the last rate case, the Chamber recommended holding 41.6% of the LCM/EPU project in Construction Work in Progress ("CWIP") (with Allowance for Funds Used During Construction ("AFUDC") offset) until the plant is operating at 671MW.[13] Xcel cannot reasonably or reliably

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[8] Id. at 32:12-25.
[9] Id. at 34:11-32.
[10] Ex. 340, Schedin Direct, at 11:5-10.
[11] Ex. 134, Clark Opening Statement at 1.
[12] Ex. 342, Schedin Surrebuttal, at 7:17-18.
[13] Ex. 340, Schedin Direct, at 3:11-4:28.

project when the EPU will serve customers in this case either.[14] Therefore the EPU costs are not used and useful and should be allowed to be recovered as initially requested by Xcel.

EPU operation at 671MW cannot be reasonably expected in the test year.

Xcel has repeatedly modified its estimates of when the plant would be operating at full capacity and currently believes it will be able to ramp up by the end of the year,[15] but the only consistency with the EPU coming on line has been the unpredictability of delivery times. With the Fukushima disaster it is understandable and delays have been seen around the country, but this is no reason to charge ratepayers that are not receiving the benefits of the EPU project. The Company cannot predictably be expected to ramp up to 671MW, so the EPU costs cannot be recovered as initially requested by the Company.

Minnesota law requires "[a]ny doubt as to reasonableness [to] be resolved in favor of the consumer."[16] Because Xcel cannot reasonably expect to operate the EPU, rates must not include the costs as initially requested by Xcel. At hearing, the Company revised its request and accepted the Chamber's proposed adjustment.[17]

(b) Chamber Adjustment

The Chamber's recommendation is that Xcel be permitted to leave the EPU in rate base, but remove depreciation expense and recover it over the remaining life of the plant.[18] The Chamber also recommended that the increased fuel costs as a result of Xcel's inability to demonstrate the EPU goal of 671MW during the test year be returned to ratepayers and collected from ratepayers over the remaining life of the plant.[19] The reasoning behind the adjustments is

[14] Ex. 342, Schedin Surrebuttal, at 4:23-29.
[15] Ex. 123, O'Connor Opening Statement.
[16] Minn. Stat. § 216B.03 (2014).
[17] Ex. 134, Clark Opening Statement.
[18] Ex. 340, Schedin Direct, at 9:20-29.
[19] Id. at 9:1-18.

that collection of increased fuel costs and allowing a plant in rate base, effectively would result in ratepayers paying twice for the power used (through cost included in rate base and again through the FCA).[20] The increased cost of fuel is a risk and cost of construction and like any other costs incurred during construction, it should be accumulated and recovered from ratepayers that benefit from the plant during its useful life.[21]

Xcel would also be required to provide updates and reporting on progress of ramping up to 671MW. The adjustments for the 2014 test year are $12,227,000 in depreciation and $11,103,828 in the FCA proceeding.[22] If there is a change in the ramp up which would result in the plant not ramping up to 671MW by the start of 2015, Xcel agrees to make the same adjustments for any period that the facility is not operating at full EPU capacity.[23]

3. Sherco 3 Fuel

The Chamber recommends the Company treat the excess fuel cost relating to the Sherco 3 outage in the same way as Xcel agreed is appropriate for Monticello's EPU outage due to inability to ramp up to 671MW. The principle is the same. Ratepayers should not pay capital costs for a resource and also pay for the replacement power when the outage is related to a capital investment intended to benefit future ratepayers.

The Chamber believes that since ratepayers are now receiving energy and capacity from the facility, the increased cost of fuel and purchased energy can now be measured, should be refunded and collected from ratepayers over the remaining life of the facility. In Xcel's last rate case, the Company was permitted to recover the capital costs by adding them to rate base, as well

[20] Ex. 342, Schedin Surrebuttal, at 4:23-5:5.
[21] Ex. 340, Schedin Direct, at 9:8-13.
[22] Ex. 140, Heuer Opening Statement, at 3; and Ex. 340, Schedin Direct, at 9:1-18.
[23] Transcript Perkett, Vol. 2 at 77:22 to 78:1-15.

as some expenses, but a decision on fuel and purchased energy was not made.[24] In making this decision, the Commission made it clear that a balancing of equities was being done and further review would be necessary when interruption were complete.[25] Since capital was being recovered and fuel and purchased energy was also recovered through the FCA, current ratepayers have paid twice for the power. But for the construction project and capital addition intended for the benefit of future ratepayers, the redundant and additional FCA costs would have not been incurred.[26]

These FCA costs should be accumulated and recovered from future ratepayers like any other cost of construction is capitalized and recovered from ratepayers that benefit from use of the asset.[27] A regulatory asset should be created and current ratepayers should not be required to pay for this asset.

The Company has calculated the adjustment to be $60,486,539 and has explained $50 million is the amount included in its litigation related to the outage.[28] Xcel should be ordered to make a filing proposing the adjustment of not less than $50 million in its open AAA proceeding.

4. Property Taxes

The Chamber recommended the Company use updated tax costs for this rate case.[29] As proposed by the Department, the Company accepted the proposal to cap the costs at updated

[24] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of the Application of Northern States Power for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961 ("*2012 Xcel Order*") (September 3, 2013) at 22-23.
[25] Id.
[26] Ex. 340, Schedin Direct, at 14:11-17.
[27] Id. at 14:27-30.
[28] Ex. 341, Schedin Direct, Attachment 13, MCC IR No. 237 Public, Attachment A (NSP response to OAG IR No. 001, calculations shown on p26, discussion at 4-5).
[29] Ex. 342, Schedin Surrebuttal, at 12:4-16.

level and adjust it downward if actual accruals are lower at year end.[30] Because the Department's recommendation satisfies the limits contained in the Chamber's proposal, the settlement is acceptable.

5. Sales Losses

The Chamber objected to aspects of a DSM adjustment to sales due to compensation provided in the Conservation Improvement Program.[31] The Chamber accepted the Department proposal accepted by the Company.[32]

6. Transmission

The Chamber recognizes that overall Xcel's transmission system is reliably designed, but remains concerned on the upward pressure with respect to costs and the lack of cost controls for both CN and non-CN projects.[33] While Xcel does not perceive a need for cost caps on transmission, limits on recovery compared to projections are appropriate, similar to caps on Xcel's other capital additions.[34]

While Xcel does performance reviews for some project management level personnel, there is a lack of accountability at a Vice President level.[35] With over $1.6 billion going into current transmission projects, this is certainly a material issue with material impacts and great uncertainty.**[36]** While these projects are submitted to MISO, there is no cost prudency review done at that level.**[37]** This lack of responsibility does not provide enough incentive for cost

[30] Transcript Duvel, Vol. 1 at 138:25 to 139:1-8.
[31] Ex. 345, Maini Surrebuttal, at 5:2 to 10:2.
[32] Ex. 145, Maini Opening Statement at 1.
[33] Ex. 342, Schedin Surrebuttal, at 10:1-8.
[34] Id. at 11:4-19 (explanation that costs on transmission projects should not be treated any different than other capital projects like Nobles wind, which was compared to CN projections, reviewed and ultimately adjusted due to overages in costs).
[35] Ex. 340, Schedin Direct, at 17:14-17.
[36] Id. at 17:26 to 18:16.
[37] Id. at 19:24 to 20:4.

management or to ensure proper accountability at equipment, materials, labor, overhead or even subcontractor levels.[38]

The Chamber's recommendation is for Xcel to create a Key Performance Incentive for the Transmission Vice President, which would drive appropriate management of costs at a high level for the Company and ratepayers.[39]

7. Wind Recovery in Base Rates or Rider

The Company is seeking to add recovery of its 2015 wind projects in base rates despite having a fair and reasonable recovery method through their renewable rider. Regardless of inclusion in base rates, the rider will continue, so base rate treatment will not simplify rates or reduce riders.[40] Witness Clark maintained that the Company would not oppose rider recovery and observed that a rider treatment benefit would result in a single recovery mechanism.[41]

When discussing the fairness of rider treatment versus the rate base request, Witness Maini observed:

> Xcel and utilities sought rider recovery to make sure they were kept whole on these types of investments, so that they got a fair and immediate return. Allowing the Company to "advance" the rate base treatment to mid-year or give them 6 months return in the rate case when rider treatment would only give them a return for a much shorter time period (i.e., late 2015 at the earliest) is unfair to ratepayers and allows the Company to earn even prior to what a fair return is.

Xcel's request puts more risk on ratepayers and increases costs to ratepayers. Witness Maini identified the impact difference to ratepayers as $5.538 million and illustrated the difference as follows:

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[38] Ex. 342, Schedin Surrebuttal, at 11:12-19.
[39] Ex. 342, Schedin Surrebuttal, at 11:21-24.
[40] Ex. 435, Campbell Public Surrebuttal, at 12:7-9 (RES Rider would continue to be necessary for true-up of PTC).
[41] Ex. 135, Clark Rebuttal, at 28:14-25.

Table 1: Revenue Requirement Comparison of Wind Projects:
Rate Case vs. Rider Recovery

	Rate Case Treatment ($ Millions)	Rider Treatment ($ Millions)	$ Millions
Capital Revenue Requirements	Cumulative in 2015	Cumulative in 2015	Difference
Pleasant Valley & Borders w/PTC	$23.177	$17.639	$5.538
	(1)	(2)	

Notes
(1) See Robinson Direct, Table 4
(2) See response to MCC IR-151 (amount in table is cumulative 2013-2015)

[42]

Department witness Campbell also recognized that there would be a difference, but did not quantify it.[43] The Department further recognized that recovery under a rider would be more precise by allowing recovery only for those months that the projects are operating.[44] While the Department prefers recovery in rate base, Campbell does not oppose rider recovery recommended by MCC.[45]

This issue was considered in Xcel's 2008 rate case in that case Xcel was required to recover through the rider.[46] Many of the same facts exist today; Xcel would have recovered more in base rates, the parties opposed keeping costs in the rider, the rider would have to be continued in order to make adjustments in production.[47] The Commission reasoned "*it is not necessarily true that projects are moved from rider recovery to base rate recovery at the earliest*

[42] Ex. 345, Maini Surrebuttal, at 3:24-28.
[43] Ex. 435, Campbell Public Surrebuttal, at 11:4-12.
[44] Ex. 435, Campbell Public Surrebuttal, at 9:6-8.
[45] Ex. 435, Campbell Public Surrebuttal, at 12:13-17.
[46] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of the Application of Northern States Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-08-1065 (October 23, 2009) at 28-29.
[47] Id. at 29.

opportunity."[48] In this case the rider should be used and the Commission should provide an order consistent with the last time it addressed this issue.

B. CLASS COST OF SERVICE STUDY (CCOSS)

Once revenue requirements are determined, the starting point for setting rates is a Class Cost of Service Study. Choosing the appropriate method for allocating costs therefore is of great importance. There are many methods available to choose from and accepted methods vary from jurisdiction to jurisdiction. The method chosen can skew cost allocation a significant amount and result in one class paying significantly more than if the same ratepayer use and utility system were located in another jurisdiction. Xcel and the Department support use of a CCOSS method which relies on least cost planning and results in classifying significant portions of fixed production plant as energy related. However, this method is ill suited for Xcel's changing supply mix and load profile. Below, the refinements to Xcel's allocation methods are addressed and these allocations; such as costs incurred for policy purposes, costs to address concerns about lost customers/economic development rider, production plant and other production O&M allocations, advocated by the Chamber are correct. Furthermore, Xcel uses an overall method that drives more cost to commercial and industrial rates than other jurisdictions and is resulting in significant departures of large employers from Minnesota. This outcome is not good for any ratepayer class and calls for a change in CCOSS method used or at minimum, weighing of methods available that are commonly used.

A review of Minnesota rates compared to states or regions helps us assess the reasonableness of our methods and what methods should be used going forward, since this determination relies on personal opinion and judgment rather than clear rules. Minnesota

[48] Id.

Commercial rates are getting less competitive relative to the rates of other states. The Chamber has observed this trend and its impacts:

> Xcel's C&I rates are already high compared to the rates from other utilities in MN, other states and on a national basis. The proposed rate increases have the potential to adversely impact the economic activity and competitiveness of our members and pose significant challenges for customers who cannot pass costs to downstream markets due to highly competitive business conditions or who are not expanding and able to offset the increased costs through increased production or output. Further, an increasing rate trend is creating a disadvantage for our members in the marketplace and against their sister companies operating elsewhere.[49]

Xcel's commercial and industrial rates are the worst among Minnesota investor owned utilities and proposals to change the CCOSS by the Department and others will only increase this problem.[50] Maini identified this issue in Tables which illustrate Xcel Minnesota Industrial ratepayers are in the worst position analyzed over a 5 year period, 10 year period and as compared to NSP's sister companies:

[49] Ex. 343, Maini Direct at 30:19-29.
[50] Id. at 31:1-29.

Table 8: NSP-MN Industrial Rate Comparisons (2009-2013)

EEI Data - Summer Update ending 6/30	2009	2010	2011	2012	2013	% change 2009-2013
NSP - MN	6.39	6.39	6.7	6.74	7.31	14%
MN Average	5.86	5.98	6.09	6.09	6.42	10%
West North Central Average (MN,ND,SD,IA,KS,MO)	5.2	5.38	5.6	5.68	5.84	12%
National Average	6.82	6.51	6.68	6.63	6.73	-1%

Source: XLI-200, Electric Edison Institute (EEI) Summer 2013

Table 9: NSP-MN Industrial Rate Comparisons (2003-2012)

EEI Data - Winter Update ending 12/31	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	% Change 2004-2012
NSP - MN	4.47	4.67	5.12	5.79	6.19	6.84	6.36	6.49	6.82	6.83	46%
MN Average	4.28	4.48	4.69	5.15	5.63	6.5	6	5.99	6.17	6.13	37%
West North Central Average (MN,ND,SD,IA,KS,MO)		4.4	4.52	4.76	4.83	5.21	5.38	5.48	5.62	5.68	29%
National Average	5.06	5.19	5.6	6	6.15	6.66	6.63	6.71	6.64	6.6	27%

Source: XLI-200, Electric Edison Institute (EEI) Winter 2012
Note: Percent change calculated for 2004-2012 since West North Central Region number missing for 2003

Table 10: NSP-MN Industrial Rate Comparisons with Sister Companies (2009-2013)

	2009	2010	2011	2012	2013
NSP - MN	6.39	6.39	6.7	6.74	7.31
NSP - ND	6.16	5.46	5.86	6.29	6.61
NSP -SD	5.83	5.72	6.09	6.32	7.10
NSP-WI	6.24	6.46	6.7	6.98	7.15
Xcel Energy - TX	5.26	3.47	4.04	4.45	3.88
Xcel Energy - NM	6.41	4.09	4.25	4.74	4.89
NSP-WI (MI)	6.8	6.73	6.69	6.54	6.97

[51]

Xcel agreed that Minnesota Industrial customers have reason for concern, noting that despite "*seeing modest economic growth, some of our Large Commercial and Industrial customers are seeing parts of their operations move to locations outside our service area, or are continuing to see weak demand for the products they produce*".[52] In fact, the class has seen decline, significant price pressure and loss of customers in recent years.[53]

This disparity is contributing to closing of Minnesota's largest energy consumers and employers, including Ford and Verso; contributing to its largest ratepayers, including the

[51] Ex. 343, Maini Direct at 31:24 to 32:11.
[52] Ex. 38, Marks Direct at 15:20-26.
[53] Id. at 15:5-18.

University of Minnesota and Flint Hills (converting to natural gas CHP) seeking alternative supplies of electricity; and contributing to the need of special rates for those who remain.[54]

Xcel witness Sparby notes a concern on increasing rates particularly on large commercial and industrial ratepayers and observes the impact of losing large business customers is increasing rates for all others.[55] Furthermore, Sparby did not dispute the competitive position Xcel has been in, as illustrated by XLI witness Pollock, and agreed that it is important to improve competitiveness of C & I rates.[56]

While these non-cost factors speak to the reasonableness of subsidy, when determining class allocation, they also speak to the unreasonableness of selecting CCOSS allocation methods that are inconsistent with other jurisdictions and increase the problems Minnesota businesses are already experiencing.

The parties generally agree that there are three steps in the CCOSS process; Functionalization, Classification and Allocation. The Chamber's concerns in this case rest primarily in the area of Classification. The process involved is defined as:

> **Classification:** The functionalized costs are classified based on the components of utility service being provided. As described by the NARUC Manual, the three principal cost classifications are demand costs (costs that vary with the KW demand imposed by the customer), energy costs that vary with energy or kWh that the utility provides), and customer costs (costs that are directly related to the number of customers served). See NARUC Manual page 20.[57]

While not totally departing from its fundamental methodology of using the Equivalent Peaker method for classification and allocation of fixed production plant, Xcel has made efforts in this rate case proceeding to revise and correct its CCOSS. However, the Department's and

[54] Id. at 34:11-32.
[55] Ex. 25, Sparby Direct at 7:19-22, and 17:1-9 (identifying losses of Ford and Verso and that impact on declining sales).
[56] Transcript Sparby, Vol. 1 at 33:1 to 36:4.
[57] Ex. 343, Maini Direct, at 15:4-9.

OAG's recommendations would not only reverse Xcel's improvements, but if their proposals are accepted would worsen the competitiveness of C&I rates.

The parties disagree on how this classification process is to occur with respect to certain categories. In each case discussed herein it is how the cost should be broken down between energy allocators and demand allocators.

1. Allocation of Production Plant

Witness Maini best describes the difference in methods and appropriatness of each as follows:

> In general, there are two main types of methods that are commonly used to classify fixed production plant – Peak Demand or Straight Fixed Variable Method and Energy Weighting Method.
>
> In the **Peak Demand** or **Straight Fixed Variable method**, all fixed production plant is classified as demand related and the costs are allocated to rate classes on demand factors that measure the class contribution to system peak. The number of peaks to be used is a function of how capacity obligations are determined. This approach recognizes that fixed costs do not vary with usage and should be classified as demand related. Further, all production plant must be available and on line to meet the peak demand requirements. There is excess capacity during the off peak periods due to lower consumption which does not contribute to the need for full production capacity throughout the year.
>
> In the **Energy Weighting methods**, portions of fixed production plant are classified as energy related. This method is based on the theory that generation is built to serve energy and capacity needs. Xcel utilizes the energy weighting method called stratification or equivalent peaker (EP) method to classify fixed production plant as demand and energy related. In this method, peaking plant costs are considered 100% demand related. Generation costs up to the costs of a peaking plant are classified as demand related and costs in excess of that are classified as energy related. For example, regarding Xcel's nuclear related fixed production plant costs, only 20.9% are considered demand related and the rest is considered energy related. The Equivalent Peaker method is based on the premise that all costs in excess of a peaking plant are incurred to save on fuel expenses. The table below shows Xcel's classification of fixed production plant costs as capacity or energy related.

Table 4: Stratification Allocation by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$770	$770 / $770	100.0%	0.0%
Nuclear	$3,689	$770 / $3,689	20.9%	79.1%
Fossil	$1,976	$770 / $1,976	39.0%	61.0%
Combined Cycle	$1,020	$770 / $1,020	75.4%	24.6%
Hydro	$4,519	$770 / $4,519	17.0%	83.0%

Source: Witness Peppin Direct, Table 5, page 13.[58]

Maini explained the problems with selecting the Equivalent Peaker method as follows:

> by classifying portions of fixed production plants to energy, the method results in allocating these classes on the basis of the energy allocator which ultimately get recovered through energy charges in rates. Since Xcel is concerned about declining sales, recovering fixed production plant costs through energy charges will necessarily result in lower cost recovery if sales are declining. However, customer classes that use less energy, but contribute more towards system peak demand do not get their fair share of cost allocated to them or pay for these costs. Yet, these fixed production costs represent the capacity used to serve the valuable purpose of meeting system peak demand and planning reserve margin requirements. In a period where Xcel expects to be capacity deficient in the 2017-2019 time frames, it would make sense to send more appropriate pricing signals regarding this matter.
>
> By classifying portions of fixed production plant as energy related, the resulting cost allocation to classes also has the unintended consequence of discouraging customers in various classes from improving load factors because each additional kWh of off-peak usage results in additional base load fixed costs (return, depreciation, fixed O&M expenses) being assigned to the rate class.
>
> Xcel's generation mix is changing and includes more than 1000 MW of wind generation and the Commission also approved an additional 750 MW of wind generation last year. Since wind generation typically produces more output in the off peak hours, sending signals to discourage off peak usage and at the same time introducing generation that produces more off peak usage is counter-productive. Furthermore, as resources get added for policy reasons, the EP theory of the dual nature of resources to serve energy and demand needs no longer holds. These resources are being added for reasons other than reliably serving energy or capacity need. I discuss this issue later in the testimony regarding classification and allocation of wind generation.
>
> For all these reasons, I believe that alternative methods should be considered. At a minimum, efforts should be made to refine the EP method...[59]

[58] Ex. 343, Maini Direct, at 16:16 to 17:14.
[59] Ex. 343, Maini Direct, at 17:16 to 18:25.

As discussed by Maini the Straight Fixed Variable (SFV) method is more appropriate in light of the forgoing concerns. Ms. Maini articulated the reasons the SFV method works better:

> …with respect to pricing signals, this method will send the appropriate pricing signals to customers in various classes regarding the value of capacity in an environment where Xcel is expected to be capacity deficient. Furthermore, it will appropriately discourage customers from contributing to peak summer demand. In addition, it will also not result in the unintended consequence of discouraging off peak usage when wind generation is more prevalent.
>
> In the last rate case, the ALJ concluded that I have not responded to the Commission's emphasis on the need to recognize the dual nature of base load plants. However, ultimately, the theory behind assessing the dual nature of base load plants is the issue of minimizing total system costs. The SFV method is also consistent with the notion of least cost planning and minimizing total costs. The straight fixed variable method takes the perspective that the plant capacity (and therefore, the capital investment) is built to serve demand and reserve margin requirements and is all demand related, and the throughput derived from it (and therefore, the fuel and other variable costs) is to serve energy needs and is energy related. The perspective regarding the straight fixed variable method is recognized and valid. This method has a solid rationale and does follow how utilities do their resource planning.
>
> The peak demand or straight fixed variable method classifies all fixed production plant as demand related since the plant capacity is required to meet peak demand and reserve margin requirements. Therefore, the cost of the plant capacity is assigned to customers on the basis of their demand. These are costs incurred in direct relationship to the MWs of demand that customers place on the system. These costs do not vary with the amount of energy consumed. Variable costs such as fuel on the other hand, do vary with energy consumption and are appropriately classified as energy related and allocated on that basis.[60]

Regardless of Xcel's selection of method for breaking down Fixed Production Plant after Capacity portion is determined, the Chamber does agree with the continued use of the D10S allocator.

(a) D10S allocator for Fixed Production Plant Capacity

[60] Ex. 343, Maini Direct, at 19:3 to 20:2.

Once Capacity is broken out for Fixed Production Plant, as Xcel has done in the past, it is appropriate to continue to use the D10S allocator. Witness Maini explained the appropriateness of its use:

> Xcel adds resources to its system in order to meet peak demand which occurs in the summer. Further, the basis of using summer peak to allocate costs classified as demand related is also consistent with MISO's new rules that went into effect on June 1, 2013. The rules state that the planning reserve margin requirements must be based on a utility's peak coincident peak, which is in the summer. Xcel's peak has a high coincidence factor with MISO's peak and Xcel will be basing its firm capacity obligations based on this single coincident peak.
>
> Customer classes contributing to these highest demands are the cost causers for capacity requirements for reliability purposes. For example, if a customer class contributes 20% to the system peak demands, they represent 20% of the need for the generating capacity and therefore should be assigned or allocated 20% of the costs.[61]

The method should continue to be used, as the Commission ordered in Xcel's last rate case.

2. Allocation of Other Production O&M

Xcel was ordered to analyze allocation Other Production O&M for this rate case. Other Production O&M includes allocation of all non-capital and non-fuel items such as labor, hardware, software, networking expenses, etc. Xcel conducted analysis using two methods namely the "location" and "predominant nature" methods. Xcel proposes to use the predominant nature method for allocation. The Chamber agrees this is the best method for Xcel's system.[62]

Witness Maini explained and analyzed the methods as follows:

> Xcel did a detailed analysis to examine the nature of the expense and identify costs that vary with energy usage and should be classified and allocated on the basis of energy and those that are fixed and should be classified and allocated on the basis of demand. In the location method, the fixed nature of expenses such as labor expenses or computer expenses varies according to whether the labor is located at a peaking plant versus a base load plant – this does not [get to] the heart of whether the expense is fixed or variable.

[61] Ex. 343, Maini Direct, at 21:4-23.
[62] Id. at 25:9-20.

> The fact that certain costs are fundamentally fixed in nature while others are variable should be the principle used to classify and allocate these costs. [63]

Maini provided further support in Surrebuttal in response to criticism by the Department who appear to want consistency with the outcome of the last case, despite the order to analyze alternate methods.[64] It was further noted that "*the NARUC manual characterizes the Predominant Nature method as a commonly used method and the Location method as not standard practice.*" [65] Maini also observed that *"the FERC method is consistent with the Predominant Nature method"* and *"Xcel classifies Other Production O&M at a jurisdictional level on this basis."*[66]

For these many reasons, the Predominant Nature method is most appropriate for Xcel's system.

3. Treatment of Nobles and Grand Meadow Wind Generation

The Chamber's position is that Xcel should allocate least-cost wind investments according to its standard CCOSS methodology, but disagrees with its use when assets are not least-cost and added for policy reasons. The Department believes Stratification should be used, but bases this conclusion on the presumption that Nobles and Grand Meadow were added as a "least cost" resource.[67] Xcel has maintained that these resources were not "least cost" resources, rather they were "least cost <u>renewable resources</u>".[68] There is a material difference in the meaning of these least cost conclusions, which results in the conclusion that Stratification method should not be used.

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[63] <u>Id</u>.
[64] Ex. 345, Maini Surrebuttal, at 17:19-27.
[65] <u>Id</u>. at 17:29-30.
[66] <u>Id</u>. at 18:1-3.
[67] Transcript Ouanes, Vol. 4 at 107:9 to 108:3.
[68] Ex. 102, Peppin Direct, at 27:12 to 28:2.

The Department portrays this issue as a big change in position for Xcel and for treatment of costs and design in general. It is not, even if it were, that would not be determinative on the issue. In the last rate case the Department advocated for allocation consistent with the CIP rider, which was a significant change from base rate treatment for Xcel.[69] This is the same as what is occurring here – Xcel and others are advocating for recovery consistent with RER rider recovery. This allocation issue for Nobles and Grand Meadow has been discussed and contested in several proceedings and it was fully addressed in the 2010 Renewable Rider proceeding.[70] In that case the Commission reasoned:

> Both in Xcel's last rate case order and in the order approving Xcel's 2010 RES rider, the Commission noted that it might become necessary to adopt more complex rider rate designs than the current per-kilowatt-hour surcharge, if riders continued to recover higher cost balances over longer periods of time. In fact, in the order in the Company's last RES rider docket, the Commission directed parties to collaborate in developing and exploring an alternative rate design methodology to the straight energy methodology, to be examined in its 2011 RES rider update filing. The Commission specifically required Xcel to include as one approach a proposal which reflects the allocation of the RES rate adjustment based on a percentage of revenue basis (or interim rate method), as a means to apply rider charges to customer bills.
>
> After consideration of the issue, the Commission concurs with the parties that the percent of revenue, or interim rate allocation method, for the RES rider is reasonable, administratively simply, and will so adopt. [71]

The reason it was a complex issue at that time remains the case now – how to allocate costs that are not least cost, is not straightforward.

(a) "Least Cost" or "Least Cost Renewable Resources"

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[69] *2012 Xcel Order* at 41-42.

[70] ORDER APPROVING 2011 RES RIDER AND 2010 TRACKER REPORT, ESTABLISHING 2011 RES CHARGE, AND REQUIRING REVISED TARIFF, *In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, Regarding the 2011 Renewable Energy Standard Rider and the 2010 RES Tracker Report*, Docket No. E-002/M-10-1066 (October 17, 2011) at 4.

[71] Id.

Xcel has maintained that Nobles and Grand Meadow were not least cost.[72] Ouanes acknowledged Resource Planning had to "force" Nobles and Grand Meadow into their Integrated Resource Plan in order for them to be select.[73] Despite these acknowledgements and consistency with the investments not being least cost, the Department maintains they were least cost. The Department asserts that "least cost renewable resource" does not mean it was not an overall least cost resource.[74] Admittedly, this is difficult to articulate in this brief as it is a confusing position. But, more important to this issue, it does not mean it was a least cost resource – and Xcel actions of forcing them into resource planning and request for exemption for certificate of need – tell us that they were not least cost. Ouanes could not explain why it would be forced for resource planning if it actually were least cost.[75]

Ouanes did not participate in the resource plans or wind selection process for these resources, but reviewed prior Xcel rate case testimony and has determined Xcel's position was that they were least cost.[76] The problem with witness Ouanes' conclusion is that, nowhere in the quotes is the issue of "least cost" squarely addressed – allocation was. Those cases dealt with allocation, the closest the Xcel and Commission gets on the issue is the statement "it does not follow that those resource are necessarily not least-cost."[77] This case is correctly first focusing on "least cost" and Xcel unequivocally maintains they were not least cost. Those cases focused on the lack of evidence that they were not least cost.

As stated above, in this case Xcel has clearly stated Nobles and Grand Meadow were not least cost. Resource Plans needed to force Nobles and Grand Meadow in order to have them

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[72] Ex. 102, Peppin Direct, at 27:12 to 28:2.
[73] Transcript Ouanes, Vol. 4 at 124:15-24.
[74] Id.
[75] Id.
[76] Ex. 408, Ouanes Direct, at 24:20 to 26:44.
[77] Id. at 26:23-35

selected. Admittedly, Xcel is changing allocation method and so can be clear about the cost of the projects as opposed to being elusive as they have in the past.

(b) Allocation for resources that are not "Least Cost"

Neither, the Department nor the NARUC manual attempt to give guidance on allocation of resources that are not least cost.[78] The Chamber recognizes that Xcel's proposed method is an appropriate one, but also offers another reasonable method for policy additions:

> the classification and allocation be based on the percent of base revenues, the "Percent of Base Revenue" method. Such an approach would recognize that resources built for policy reasons are neither built to reliably serve capacity or energy needs. The Percent of Base Revenue approach implicitly has elements of energy and demand, mimics the current rate design for all customers and by applying the same percentage to all customer classes, it recognizes the policy nature behind the investment. This method is also used currently in Xcel's RER Rider, and was implemented only after rigorous debate and analysis at the Commission.[79]

Analysis of the history on these projects makes it clear that Xcel would not have invested in them if there was not a law that Xcel had to comply with. As a result the cost-causer of these investments was a policy one – not strictly a least cost one. Xcel has proposed that these cost be allocated 100% to capacity and the Chamber does not object to this. The Chamber's primary position is that order should allocate Nobles and Grand Meadow in the same way as the RER Rider, "Percent of Base Revenue" method, alternatively the Chamber accepts Xcel's proposed method.

4. Allocation of Economic Development Discounts

The Chamber disagrees with the method proposed by Xcel, the "present revenues" method. The most accurate method that should be used is the "base revenues" method.[80] The reason the base revenue method is appropriate is that the discount is associated with the

[78] Transcript Ouanes, Vol. 4 at 110:18 to 111:17.
[79] Ex. 343, Maini Direct, at 23:11-21.
[80] Ex. 343, Maini Direct, at 30:4-8.

contribution of fixed costs (i.e., base revenues) that the customer made prior to the discount.[81] Maini further explained that retaining customers is not strictly for the purpose of retaining energy consumption, rather, it is for retaining base revenues.[82] At hearing witness Ouanes agreed that the objective of the discounts is retaining customers and retaining customers would reduce fixed and variable costs.[83] Since the driving purpose or cost-causer of the program is to retain customer base revenues and contribution to the system the "base revenue" method is appropriate.

C. <u>REVENUE APPORTIONMENT</u>

The Chamber's position with respect to revenue allocation is that the Commission should not deviate far from the CCOSS when apportioning revenue responsibility. While it is true that both cost and non-cost factors should be contemplated when designing rates,[84] it is *cost* that is to be the starting point when determining apportionment among the classes.[85] If the CCOSS has been performed correctly, then the output of the CCOSS should reflect accurate class allocation. Significant deviation from CCOSS-based apportionment for non-cost factors results in some customer classes subsidizing others. In particular, the effect will be a disproportionately large rate increase for non-residential customers, whose electric bills already constitute a substantial component of total operating costs.

The Chamber appropriately weighed non-cost factors and discussed them above, in introductory comments on Class Cost of Service Study. What is not covered above, is how to allocate costs if CCOSS methods supported by Xcel and the Chamber are ordered – how should the change in CCOSS impacts be reflected in final rates. Two factors will impact final

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[81] Id, at 7-8.
[82] Ex. 345, Maini Surrebuttal, at 19:12-17.
[83] Transcript Ouanes, Vol. 4 at 83:24 to 84:6.
[84] <u>See</u> *St. Paul Area Chamber of Commerce v. Minn. Public Serv. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977).
[85] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of Minnegasco,* Docket No. G-008/GR-95-700 (June 10, 1996) at 52-53.

allocations; 1) methods incorporated into final CCOSS; and 2) reductions to the revenue requirement. As the Chamber believes allocation should follow costs in this case as close as possible, the CCOSS allocation should be closely followed and once the CCOSS methods are determined, the percentage of class responsibility can be set and largely followed. Any reduction to recovery can be followed by proportionally reducing each class by the same percentages determined in the final CCOSS.

1. Apportionment if Department CCOSS is not Accepted.

The Chamber does not anticipate the Commission will accept either the CCOSS of the Company or the Department in its entirety. The Department's position is that regardless of the final CCOSS, the adjustment to final rates must be made from the final CCOSS as set by the Commission.[86] This follows Commission policy, which maintains it is *cost* that is to be the starting point when determining apportionment among the classes.[87] The Chamber Agrees.

For 2015 to follow Commission policy, that classes are to move closer to cost, any deviation from CCOSS in 2014 should be eliminated. An across the board increase does not accomplish this.

D. <u>RATE DESIGN</u>

1. Interruptible Rates

The Chamber is concerned that Interruptible ratepayers are proposed to be undercompensated and detrimental effects could be felt to Xcel's entire system. Xcel's past position on this issue has not been to refute value brought to Xcel's system and ratepayers, likewise Xcel has not refuted that interruptible customers have real costs, but Xcel has simply argued an increase in the credit is not necessary to retain the customers. The same position was

[86] Transcript Pierce, Vol. 4 at 149:21 to 150:6.
[87] FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, *In the Matter of Minnegasco,* Docket No. G-008/GR-95-700 (June 10, 1996) at 52-53.

taken at the onset of this case and while there was a modest increase in the credit, it did not keep up with past increases in demand charge (no increase in interruptible credit in last rate case) or even the increase in this case (11.7% increase in demand at secondary levels, but only 6% increase in credit).[88] The Department took the same position as Xcel, that an increase in the credit was not necessary to retain customers, and dropped the proposed credit to 3%, even lower than what Xcel proposed.[89] Xcel and the Department's position, is based on a presumption that interruptible customers have been retained. This is wrong – Xcel has lost interruptible customers.[90]

After filing testimony, the Company more closely reviewed retention of interruptible participation and found that there has been a drop off that is likely a result of the lack of credit.[91] Xcel further acknowledged that if there is a need for resources in resource planning, these resources would need to be replaced.[92] The Commission should recognize that all customers benefit from interruptible rate participation, regardless of the number of actual interruptions called, because Xcel's resource requirements and future capacity additions are reduced by the amount of participation. While it is obvious, this loss of this resource will likely cost more to replace and run counter to Minnesota's policy to advance conservation. Xcel acknowledged there is a conservation element when asked about building out generation and transmission.[93]

Witness Maini documented that the cost for replacement of the interruptible customers is higher and that the credit is undervalued as compared to avoided cost used by the Company. The applicable excerpts are:

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[88] Transcript Huso, Vol. 2 at 181:12 to 182:15.
[89] Ex. 420, Pierce Surrebuttal at 26:1-8.
[90] Transcript Huso, Vol. 2 at 182:21-25.
[91] Transcript Huso, Vol. 2 at 183:1-11.
[92] Transcript Huso, Vol. 2 at 183:18-22.
[93] Transcript Huso, Vol. 2 at 184:4-18.

Q. WHAT ARE THE INTERRUPTIBLE CREDIT CALCULATIONS BASED ON?

A. As indicated in my and Chamber witness Schedin's testimony in the last rate case, the calculations are based on the avoided capacity costs.

Q. HAVE THERE BEEN ANY RECENT PROCEEDINGS THAT HAVE ADOPTED THE AVOIDED CAPACITY COSTS?

A. Yes; as indicated by Chamber witness Schedin, the Commission adopted the avoided capacity cost in the solar docket 13-315 on May 1, 2014. In this proceeding, the Commission adopted the avoided capacity cost of $10.63/KW-month or $127.56/KW-year. This amount is very close to the avoided cost estimate that witness Schedin included in his testimony in the last rate case of $10.18/KW-month. Further, similar values are used to calculate avoided capacity cost savings associated with implementing CIP programs.

Q. HOW DO XCEL'S PROPOSED INCREASES TO THE INTERRUPTIBLE CREDIT COMPARE TO THE AVOIDED CAPACITY COST OF $127.16/KW-YEAR?

A. As noted on Table 13, the proposed increases in interruptible credits result in an annual credit ranging from $37.80/KW-year to $70.20/KW year or 30% to 55% of the avoided capacity cost. Consequently, while I appreciate Xcel's efforts to raise the interruptible credits, I am concerned that these proposed increases still understate the value of the interruptible load. [94]

The credit should be higher than what Xcel proposed. The Chamber's calculation is based on Xcel's own CIP avoided cost. Xcel acknowledged that a reasonable cost to use for avoided cost is what the Company uses in its own CIP cost-benefit analysis.[95] This certainly seems reasonable to allow ratepayers to benefit from the same calculation Xcel uses to determine its own incentive payment. Based on the avoided cost used by Xcel for CIP incentive payments, the credit could be set as high as $127.56/KW-year.[96] The increase proposed by the Chamber does not go that high - $77.24/KW year at the highest and the relationships with other

[94] Ex. 343, Maini Direct, at 37:28 to 38:28.

[95] Transcript Huso, Vol. 2 at 185:2-12.

[96] Ex. 343, Maini Direct at 38:7-15.

performance factors and tiers be accordingly adjusted[97] - other ratepayers will still benefit in the form of lower cost resources than if a peaking plant were built.

As stated above Xcel has lost interruptible participants. The drop in participants indicates there are costs to remain on the program, regardless of the number of interruptions that occur. In the past few years, there has been a loss of 136 participants and 67MW.[98] Witness Maini identified some of the costs as "*additional employee costs (engineers and others that were necessary to hire), monitoring and testing, reporting and overtime costs, capital costs for compliance of RICE compliance, fuel costs regardless of being called on (fuel must be rotated as it does have a useful life).*"[99] Despite the Department's concern that there have not been many interruptions,[100] customers are not getting a free ride, there is cost regardless of interruption. As the drop in participation shows, if the credit is not sufficient, customers will drop off and replacement resources will have to be purchased at higher cost.

Xcel's Integrated Resource Plan supports the Chamber's position. Demand Response was ordered to be reviewed for expansion in Xcel's last Integrated Resource Plan order.[101] Specifically, Xcel was ordered to evaluate "*achieving participation rates in for demand response programs in the top 25 percent*" and to "*evaluate higher levels of cost-effective and feasible demand response*".[102] The opposite is happening – participation is dropping and the Chamber's cost-effective proposal should be accepted. Demand Side Management efforts must be

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97 Ex. 345, Maini Surrebuttal, at 25:19-27.
98 Ex. 145, Maini Opening Statement at Attachment A, answers to b and c, since 2010.
99 Ex. 345, Maini Surrebuttal, at 24:19-25.
100 Ex. 420, Pierce Direct at 26:12-16.
101 ORDER ESTABLISHING PROCEDURAL SCHEDULES AND FILING REQUIREMENTS, *In the Matter of Xcel Energy's 2011-2025 Integrated Resource plan*, Docket No. E-002/RP-10-825 ("*2010 Xcel IRP ORDER*") (November 30, 2012) at 12.
102 Id.

implemented through rates – this is exactly the time and place to put into effect objectives of the IRP.

In past cases, the Chamber has noted concern and warned that customers have indicated they would leave the interruptible program because the credit was not keeping up with rate increases and there was not enough value based on the costs they incur. In this case, Xcel has verified that this circumstance has come true – there has been a loss of participation. The order in this case must direct Xcel to increase the interruptible credit to $77.24/KW-year for Tier1 Performance Factor C and the relationships, with other performance factors and tiers be accordingly adjusted.

2. Definition of Contiguous

The Chamber observed that there is ambiguity in Xcel's definition of Contiguous and its application in various tariff applications. In order for ratepayers to receive appropriate price signals, for fairness and for giving ratepayers the ability to plan their facilities, clarity <u>must</u> be provided in the rules. This definition impacts among others, Solar applications, Coincident peak billings, and ability to develop Distributed Generation.[103] The definition in Solar law is what is appropriate and clear:

> (e) "Contiguous property" means property owned or leased by the customer sharing a common border, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way.[104]

If customers cannot combine their load at any one contiguous campus, or otherwise participate in Distributed Generation across roadways and other easements on property which they control, Distributed Generation efforts will be stifled as economies of scale will not be able to be achieved. Additional support for the Chamber's proposal is found in Xcel's last Integrated

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[103] Transcript Schedin, Vol. 3 at 187:8-22.
[104] Minn. Stat. § 216B.164, Subd. 2a,(e) (2014).

Resource Plan which states Xcel should evaluate "*higher levels of distributed generation, including industrial-sized distributed generation… and combined heat and power*."[105] Customers cannot practically consider industrial-sized distributed generation of combined heat and power if their campuses are broken up and they cannot propose projects that have economies of scale. The above definition should be incorporated in Xcel's Rules.

3. Coincident Peak Billing

In addition to the change in the definition of Contiguous, as proposed by the Chamber, the rules for Coincident Peak Billing should be expanded to allow this option for customers taking delivery at two or more service points above the 500KW threshold on contiguous properties.[106] As explained by Chamber witness Schedin:

> Coincident peak billing is a concept applicable to a C&I demand-billed customer taking service at two or more connections under one authority on parcels of land which are contiguous or adjacent. Under coincident peak billing, the 15-minute billing demands of each service connection are synchronized and added together at the same intervals in time, so the peak demand of the subject connections aggregated for each 15 minute interval is the basis for demand billing rather than the separate peak demands on each of the service connections, which often peak at different times.
>
> And
>
> Coincident billing is appropriate, fair and reasonable, because it allows a customer to capture the diversity benefits that the customer provides to the system entirely from its own operations, rather than absorbing it into the system and allowing other customers benefit from the customer's diversity.[107]

Xcel's main objection to this change is that they will have to recover the costs from other ratepayers and customers can rewire their own facilities to achieve the same result.[108] Schedin

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[105] *2010 Xcel IRP Order* at 12.
[106] Ex. 340, Schedin Direct at 25:20 to 26:6 (noting that there would be only nine customers affected, limiting the revenue impact to Xcel or other ratepayers).
[107] Ex. 340, Schedin Direct at 24:8 to 25:5.
[108] Ex. 107, Huso Rebuttal at 43:4-10.

explained that this solution is not practical nor is it efficient for customers to redesign a system that can be efficiently managed with technology.[109]

Setting a threshold, as the Chamber's proposal does, to two or more service points above the 500KW, limits the diversity savings allocated to other customers while allowing the coincident billing customers to capture the diversity which they create. Setting a size threshold also satisfies the Commission's concerns in the last rate case that impacts of Coincident Peak Billing adjustment proposed would result in reasonable rates.[110] The Chamber's proposal would only impact nine customers which would not result in unreasonable adjustment to others.

E. <u>OTHER ISSUES</u>

1. Fuel Cost Recovery Reform

All parties that have provided testimony on Fuel Cost Recovery ("FCA") reform have observed that efforts have trailed on and the issue should be formally addressed in the near future.[111] The intervening parties' concerns stem in part with there being no incentive to manage costs prudently and no penalty if not done.[112] Xcel therefore, has no incentive to add oversight and risk of no return, delay is good for Xcel. There is no deadline or motivation for the Company to move this forward, so the Commission needs to provide one in an order. The Chamber proposal is a reasonable one - If resolution is not gained in the AAA proceeding by the time the next rate case is filed, Xcel must file a plan in that proceeding.[113]

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[109] Ex. 342, Schedin Surrebuttal, at 14:6-12.
[110] *2012 Xcel Order,* at 13.
[111] Ex. 345, Maini Surrebuttal at 27:7-18, See also, Ex. 263, Pollock Surrebuttal at 33:1 to 34:9, See also, Ex. 412, Ouanes Rebuttal at 13:7 to 14:2 (noting that the last discussions occurred June 5, 2013).
[112] Ex. 343, Maini Direct at 41:26 to 42:22, See also, Ex. 260, Pollock Direct at 5:11 to 27:18, See also, Ex. 412, Ouanes Rebuttal at 13:10 to 14:2.
[113] Ex. 345, Maini Surrebuttal at 27:7-13.

2. Peer Benchmarking

The Chamber witness Maini noted:

> There are areas of concern with respect to various cost benchmarks of NSPM against its sister companies, as well as peers. Attachment A, page 4 shows a comparison summary followed by graphs by each category. As page 4 indicates, NSPM is consistently trending below even the second quartile (in the bottom half) with respect to the following cost categories:
>
> - Non fuel operations and maintenance ”O&M” benchmarks such as a percent of retail revenue by total, per customer, per retail MWh sales, per MWh generated
> - Transmission O&M benchmarks such as transmission O&M per line mile, transmission O&M per MWH throughput
>
> Administrative and General ”A&G” and customer care benchmarks are in the second quartile. While distribution O&M per retail customer is in the top quartile, distribution O&M per MWh retail sales is in the second quartile.[114]

The Chamber observed that that there are several areas that Xcel needs to improve significantly as compared to peers and sister companies.[115] The Department agrees that that the Chamber's proposal is appropriate and <u>all costs</u> should be measured.[116] The order should have Xcel utilize the various non-fuel and transmission O&M cost benchmarks in the peer benchmarking analysis that are not in the first or second quartile as key performance indicators to help improve the efficiency in Xcel's operations.

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[114] Ex. 343, Maini Direct at 43:28 to 44:6.
[115] Ex. 343, Maini Direct at 44:8-16.
[116] Ex. 412, Ouanes Rebuttal at 16:14-20.

IV. CONCLUSION.

Based on the foregoing discussions, the Chamber urges the Administrative Law Judge to make findings and conclusions consistent with the Chamber's arguments.

Respectfully submitted,

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