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	**)**	

MINNESOTA CHAMBER OF COMMERCE PROPOSED FINDINGS OF FACT

October 14, 2014

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I. INTRODUCTION

In order to avoid duplication the Chamber's[1] proposed Findings of Fact will be limited to items that remain disputed between the Chamber and another party. In the instances where the Chamber's position is largely consistent the Department or Xcel, Proposed Findings are included on those issues that are intended to supplement the Department or Xcel's Proposed Findings.

II. Findings of Fact

A. REVENUE REQUIREMENT ISSUES

1. Prairie Island

1. The Chamber does not object to the Department proposal.[2]

2. Monticello EPU

(a) Used and Useful

2. 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.[3] Xcel cannot reasonably or reliably project when the EPU will serve customers in this case either.[4]

[1] In the interest of brevity, all defined terms and phrases, including citations, utilized in the Chamber's Initial Brief are incorporated in these Proposed Findings of Fact unless otherwise defined herein.
[2] Ex. 342, Schedin Surrebuttal at 7:17-18.
[3] Ex. 340, Schedin Direct at 3:11-4:28.
[4] Ex. 342, Schedin Surrebuttal at 4:23-29.

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.

3. 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,[5] 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.

4. Minnesota law requires "[a]ny doubt as to reasonableness [to] be resolved in favor of the consumer."[6] Because Xcel cannot reasonably expect to operate the EPU, rates must not include the costs as initially requested by Xcel.

5. At hearing, the Company revised its request and accepted the Chamber's proposed adjustment.[7]

(b) Chamber Adjustment

6. 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.[8] 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

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[5] Ex. 123, O'Connor Opening Statement.
[6] Minn. Stat. § 216B.03 (2014).
[7] Ex. 134, Clark Opening Statement.
[8] Ex. 340, Schedin Direct at 9:20-29.

and collected from ratepayers over the remaining life of the plant.[9] Xcel would also be required to provide updates and reporting on progress of ramping up to 671MW.

7. The reasoning behind the adjustments is 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).[10] 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.[11]

8. The adjustments for the 2014 test year are $12,227,000 in depreciation and $11,103,828 in the FCA proceeding.[12] 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.[13]

3. Sherco 3 Fuel

9. 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.

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

10. 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.

11. In Xcel's last rate case, the Company was permitted to recover the capital costs by adding them to rate base, as well as some expenses, but a decision on fuel and purchased energy was not made.[14] 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.[15] Since capital was being recovered and fuel and purchased energy was also recovered through the FCA, current ratepayers have paid twice for the power.

12. 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.[16]

13. The 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.[17]

14. Rate cases are intended to be comprehensive reviews of a utility's rates and are an appropriate place to address all costs related to any project that recovery is being requested for. If an issue can be addressed in a rate case and sufficient facts are known on

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[14] 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.

[15] Id.

[16] Ex. 340, Schedin Direct at 14:11-17.

[17] Ex. 340, Schedin Direct at 14:27-30.

that issue, it should be addressed, not deferred for the convenience of the utility… at the expense of the intervenor.[18]

15. 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.[19]

16. Xcel must make a filing proposing the adjustment of not less than $50 million in its open AAA proceeding to reflect the increased cost of fuel as a result of the outage.

4. Property Taxes

17. The Chamber accepts the Department proposal.

5. Sales Losses

18. The Chamber accepted the Department proposal accepted by the Company.[20]

6. Transmission

19. 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.[21] While Xcel does not perceive a need for cost

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[18] Minn. Stat. § 216B.03, ("doubt as to reasonableness must be resolved in favor of the consumer"… so where equally valid methods are available, Commission must choose the one that favors the consumer).

[19] 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).

[20] Ex. 145, Maini Opening Statement at 1.

[21] Ex. 342, Schedin Surrebuttal at 10:1-8.

caps on transmission, limits on recovery compared to projections are appropriate, similar to caps on Xcel's other capital additions.[22]

20. While Xcel does performance reviews for some project management level personnel, there is a lack of accountability at a Vice President level.[23]

21. Xcel acknowledges that there are significant uncertainties related to these projects at the time of CON application.[24] This is exactly why additional controls are appropriate. The CON costs are a benchmark which to measure performance against, if adjustments upward are appropriate because of unknown costs or contingencies at the time of CON approval the Company could appropriately seek and obtain recovery.

22. With over $1.6 billion going into current transmission projects, this is certainly a material issue with material impacts and great uncertainty.[25] While these projects are submitted to MISO, there is no cost prudency review done at that level.[26] This lack of responsibility does not provide enough incentive for cost management or to ensure proper accountability at equipment, materials, labor, overhead or even subcontractor levels.[27]

23. Xcel must propose 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.[28]

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[22] Ex. 342, Schedin Surrebuttal 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).
[23] Ex. 340, Schedin Direct at 17:14-17.
[24] Xcel Brief at 123.
[25] Ex. 340, Schedin Direct at 17:26 to 18:16.
[26] Ex. 340, Schedin Direct at 19:24 to 20:4.
[27] Ex. 342, Schedin Surrebuttal at 11:12-19.
[28] Ex. 342, Schedin Surrebuttal at 11:21-24.

7. Wind Recovery in Base Rates or Rider

24. 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.[29]

25. Xcel does not oppose rider recovery and observed that a rider treatment benefit would result in a single recovery mechanism.[30]

26. The Chamber notes:

> 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.

27. Xcel's request puts more risk on ratepayers and increases costs to ratepayers.

28. The impact difference to ratepayers as $5.538 million and illustrated the difference as follows:

[29] Ex. 435, Campbell Public Surrebuttal, at 12:7-9 (RES Rider would continue to be necessary for true-up of PTC).

[30] 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)

[31]

29. Department agreed that there would be a difference, but did not quantify it.[32] 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.[33]

30. Department does not oppose rider recovery recommended by MCC.[34]

31. This issue was considered in Xcel's 2008 rate case in that case Xcel was required to recover through the rider.[35] 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.[36] The Commission reasoned "*it is not necessarily true that projects are moved from rider recovery to base rate recovery at the earliest opportunity*."[37]

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[31] Ex. 345, Maini Surrebuttal at 3:24-28.
[32] Ex. 435, Campbell Public Surrebuttal at 11:4-12.
[33] Ex. 435, Campbell Public Surrebuttal at 9:6-8.
[34] Ex. 435, Campbell Public Surrebuttal at 12:13-17.
[35] 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.
[36] Id. at 29.
[37] Id.

32. The Chamber identified the impact difference to ratepayers of rate base recovery over rider recovery, of Pleasant Valley and Boarder Winds, as $5.538 million for 2015.[38] When considering multiple methods of recovery and more than one can be found to be appropriate the most favorable one for ratepayers must be the method used.[39]

33. In this case the rider should be used.

B. CLASS COST OF SERVICE STUDY (CCOSS)

34. Once revenue requirements are determined, the starting point for setting rates is a Class Cost of Service Study.[40] Choosing the appropriate method for allocating costs therefore is of great importance.

35. 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.

36. 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.

37. 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

[38] Chamber Brief at 8-10.

[39] Minn. Stat. § 216B.03, ("doubt as to reasonableness must be resolved in favor of the consumer"… so where equally valid methods are available, Commission must choose the one that favors the consumer).

[40] 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.

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.

38. 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.

39. Xcel and Minnesota 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.[41]

40. 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.[42] Compared to others 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:

[41] Ex. 343, Maini Direct at 30:19-29.
[42] Ex. 343, Maini Direct 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	6.34	6.36	6.49	6.82	6.83	46%
MN Average	4.20	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

[43]

41. 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*".[44]

42. The Large Commercial and Industrial class has seen decline, significant price pressure and loss of customers in recent years.[45]

43. This higher rates of Xcel's Large Commercial and Industrial class is contributing to closing of Minnesota's largest energy consumers and employers, including

[43] Ex. 343, Maini Direct at 31:24 to 32:11.
[44] Ex. 38, Marks Direct at 15:20-26.
[45] Ex. 38, Marks Direct at 15:5-18.

Ford and Verso; contributing to its largest ratepayers seeking alternative supplies of electricity, including the University of Minnesota and Flint Hills (converting to natural gas CHP); and contributing to the need of special rates for those who remain.[46]

44. 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.[47] 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.[48]

45. 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.

46. 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.[49]

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[46] Ex. 343, Maini Direct at 34:11-32.

[47] Ex. 25, Sparby Direct at 7:19-22, and 17:1-9 (identifying losses of Ford and Verso and that impact on declining sales).

[48] Transcript Sparby, Vol. 1 at 33:1 to 36:4.

[49] Ex. 343, Maini Direct at 15:4-9.

47. Xcel has made efforts in this rate case proceeding to revise and correct its CCOSS. However, the Department's and OAG's recommendations would not only reverse Xcel's improvements, but if their proposals are accepted would worsen the competitiveness of C&I rates.

48. The parties disagree on how this classification process is to occur with respect to certain categories.

1. Allocation of Production Plant

Witness Maini best describes the difference in methods and appropriateness 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.[50]

49. 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.

[50] Ex. 343, Maini Direct at 16:16 to 17:14.

> For all these reasons, I believe that alternative methods should be considered. At a minimum, efforts should be made to refine the EP method…[51]

50. 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.[52]

[51] Ex. 343, Maini Direct at 17:16 to 18:25.
[52] Ex. 343, Maini Direct at 19:3 to 20:2.

51. Other utilities, including Duke Energy in North and South Carolina that utilizes this SFV method and similar to Xcel, its supply side resources include a diverse mix of coal, nuclear, natural gas and renewable resources.[53]

52. The SFV method an appropriate method for classifying fixed production plant, and more so now, given Xcel's changing generation mix and flat to declining energy.

(a) D10S allocator for Fixed Production Plant Capacity

53. 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.

54. 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.[54]

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

2. Allocation of Other Production O&M

56. 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

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[53] Ex. 345, Maini Surrebuttal, at 14.
[54] Ex. 343, Maini Direct at 21:4-23.

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.

57. The Chamber agrees the predominant nature method is the best method for Xcel's system.[55]

58. 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. 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.[56]

59. Commission ordered to analysis of alternate methods.[57]

60. The Chamber notes that "*the NARUC manual characterizes the Predominant Nature method as a commonly used method and the Location method as not standard practice.*"[58] 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."*[59]

61. The Department did not analyze why the predominant nature method was not more accurate, or why their favored location method is more precise, rather it was simply

[55] Ex. 343, Maini Direct at 25:9-20.
[56] Ex. 343, Maini Direct at 25:9-20.
[57] 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 (September 3, 2013) at 15.
[58] Ex. 345, Maini Surrebuttal at 17:29-30.
[59] Ex. 345, Maini Surrebuttal at 18:1-3.

that predominant nature method was not used previously.[60] This is not sufficient reason to use a less precise method of allocation.

62. The Predominant Nature method is most appropriate for Xcel's system.

3. Treatment of Nobles and Grand Meadow Wind Generation

63. 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.

64. 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.[61]

65. Xcel has maintained that these resources were not "least cost" resources, rather they were "least cost renewable resources".[62]

66. 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.

67. 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.

68. In Xcel's last rate case the Department advocated for allocation consistent with the CIP rider, which was a significant change from base rate treatment for Xcel.[63] This is

[60] Department Brief at 272-274.
[61] Transcript Ouanes, Vol. 4 at 107:9 to 108:3.
[62] Ex. 102, Peppin Direct at 27:12 to 28:2.
[63] 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 (September 3, 2013) at 41-42.

the same as what is occurring here – Xcel and others are advocating for recovery consistent with RER rider recovery.

69. 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.[64] 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.[65]

70. 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"

71. Xcel has maintained that Nobles and Grand Meadow were not least cost.[66]

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[64] 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.

[65] 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.

[66] Ex. 102, Peppin Direct at 27:12 to 28:2.

72. The Department acknowledged Resource Planning had to "force" Nobles and Grand Meadow into their Integrated Resource Plan in order for them to be select.[67] Despite these acknowledgements and consistency with the investments not being least cost, the Department maintains they were least cost.

73. The Department asserts that "least cost renewable resource" does not mean it was not an overall least cost resource.[68] Admittedly, the Department is difficult to articulate in this brief as it is a confusing position.

74. 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.[69]

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.[70] 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."[71] There has never been a finding or assertion that these investments were least cost.

76. This case is correctly first focusing on "least cost" and Xcel unequivocally maintains they were not least cost. Past cases focused on the lack of evidence that they were

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[67] Transcript Ouanes, Vol. 4 at 124:15-24.
[68] Transcript Ouanes, Vol. 4 at 124:15-24.
[69] Transcript Ouanes, Vol. 4 at 124:15-24.
[70] Ex. 408, Ouanes Direct at 24:20 to 26:44.
[71] Ex. 408, Ouanes Direct at 26:23-35

not least cost. There has never been a finding or assertion that these investments were least cost.

77. 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 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"

78. Neither, the Department nor the NARUC manual attempt to give guidance on allocation of resources that are not least cost.[72]

79. 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.[73]

80. 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.

81. Xcel has proposed that these costs be allocated 100% to capacity and the Chamber does not object to this.

[72] Transcript Ouanes, Vol. 4 at 110:18 to 111:17.
[73] Ex. 343, Maini Direct at 23:11-21.

82. The Chamber's primary position is that the 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

83. 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.[74]

84. The reason the base revenue method is appropriate is that the discount is associated with the contribution of fixed costs (i.e., base revenues) that the customer made prior to the discount.[75] The Chamber further explained that retaining customers is not strictly for the purpose of retaining energy consumption, rather, it is for retaining base revenues.[76]

85. At hearing the Department agreed that the objective of the discounts is retaining customers and retaining customers would reduce fixed and variable costs.[77] 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>

86. The Chamber's position with respect to revenue allocation is that the Commission should not deviate far from the CCOSS when apportioning revenue responsibility.

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[74] Ex. 343, Maini Direct at 30:4-8.
[75] Ex. 343, Maini Direct at 7-8.
[76] Ex. 345, Maini Surrebuttal, at 19:12-17.
[77] Transcript Ouanes, Vol. 4 at 83:24 to 84:6.

87. While it is true that both cost and non-cost factors should be contemplated when designing rates,[78] it is *cost* that is to be the starting point when determining apportionment among the classes.[79]

88. 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.

89. In particular, the effect will be a disproportionately large rate increase for non-residential customers, whose electric bills already constitute a more substantial component of total operating costs.

1. Non-Cost Factors to weigh.

90. Xcel and Minnesota 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.[80]

91. 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

[78] See *St. Paul Area Chamber of Commerce v. Minn. Public Serv. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977).

[79] 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.

[80] Ex. 343, Maini Direct at 30:19-29.

only increase this problem.[81] Compared to others 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:

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	4.20	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

[82]

92. 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*".[83]

[81] Ex. 343, Maini Direct at 31:1-29.
[82] Ex. 343, Maini Direct at 31:24 to 32:11.
[83] Ex. 38, Marks Direct at 15:20-26.

93. The Large Commercial and Industrial class has seen decline, significant price pressure and loss of customers in recent years.[84]

94. This higher rates of Xcel's Large Commercial and Industrial class is contributing to closing of Minnesota's largest energy consumers and employers, including Ford and Verso; contributing to its largest ratepayers seeking alternative supplies of electricity, including the University of Minnesota and Flint Hills (converting to natural gas CHP); and contributing to the need of special rates for those who remain.[85]

95. 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.[86] 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.[87]

2. Apportionment if Department CCOSS is not Accepted.

96. Two factors will impact final 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.

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[84] Ex. 38, Marks Direct at 15:5-18.
[85] Ex. 38, Marks Direct at 34:11-32.
[86] Ex. 25, Sparby Direct at 7:19-22, and 17:1-9 (identifying losses of Ford and Verso and that impact on declining sales).
[87] Transcript Sparby, Vol. 1 at 33:1 to 36:4.

97. Commission policy maintains it is *cost* that is to be the starting point when determining apportionment among the classes.[88]

98. 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.[89] The Chamber Agrees.

99. The Chamber'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.

100. 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. Any 2014 subsidy should be eliminated for 2015 and CCOSS ordered should be strictly followed.

3. Apportionment for 2015.

101. For 2015 to follow Commission policy, that classes are to move closer to cost, any deviation from CCOSS in 2014 should be eliminated.

D. <u>RATE DESIGN</u>

1. Interruptible Rates

102. The Chamber is concerned that Interruptible ratepayers are proposed to be undercompensated and detrimental effects could be felt to Xcel's entire system.

103. 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

[88] 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.
[89] Transcript Pierce, Vol. 4 at 149:21 to 150:6.

real costs, but Xcel has simply argued an increase in the credit is not necessary to retain the customers.

104. At the onset of this case, Xcel argued a large increase in the credit is not necessary to retain the customer. 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).[90]

105. 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.[91]

106. 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.[92]

107. 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.[93]

108. Xcel further acknowledged that if there is a need for resources in resource planning, these resources would need to be replaced.[94]

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

109. 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.

110. Loss of interruptible customers 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.[95]

111. The Chamber 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.[96]

112. The proposed credit is $37.80/KW-year to $70.20/KW year or 30% to 55% of the avoided capacity cost.[97] The Chamber's calculation is based on Xcel's own CIP avoided cost.

113. Xcel acknowledged that a reasonable cost to use for avoided cost is what the Company uses in its own CIP cost-benefit analysis.[98] It is reasonable to use the same calculation Xcel uses to determine its own incentive payment.

114. Based on the avoided cost used by Xcel for CIP incentive payments, the credit could be set as high as $127.56/KW-year.[99]

115. The increase proposed by the Chamber does not go that high - $77.24/KW year at the highest and the relationships with other performance factors and tiers be

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[95] Transcript Huso, Vol. 2 at 184:4-18.
[96] Ex. 343, Maini Direct, at 37:28 to 38:28.
[97] Ex. 343, Maini Direct, at 37:28 to 38:28.
[98] Transcript Huso, Vol. 2 at 185:2-12.
[99] Ex. 343, Maini Direct at 38:7-15.

accordingly adjusted[100] - other ratepayers will still benefit in the form of lower cost resources than if a peaking plant were built.

116. 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.[101]

117. Interruptible customers face real costs, 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).*"[102]

118. Despite the Department's concern that there have not been many interruptions,[103] customers are not getting a free ride, there is cost regardless of interruption.

119. 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.

120. 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.[104] 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*".[105] The opposite is happening – participation is

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[100] Ex. 345, Maini Surrebuttal, at 25:19-27.
[101] Ex. 145, Maini Opening Statement at Attachment A, answers to b and c, since 2010.
[102] Ex. 345, Maini Surrebuttal at 24:19-25.
[103] Ex. 420, Pierce Direct at 26:12-16.
[104] 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 (November 30, 2012) at 12.
[105] Id.

dropping and the Chamber's cost-effective proposal should be accepted. Demand Side Management efforts must be implemented through rates – this is exactly the time and place to put into effect objectives of the IRP.

121. 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.

122. Xcel must 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

123. 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.

124. This definition of Contiguous among other things, impacts, Solar applications, Coincident peak billings, and ability to develop Distributed Generation.[106]

125. The definition of Contiguous in Solar law 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.[107]

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

126. 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.

127. Additional support for the Chamber's proposal is found in Xcel's last Integrated Resource Plan which states Xcel should evaluate "*higher levels of distributed generation, including industrial-sized distributed generation… and combined heat and power.*"[108] 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.

128. The "definition" referred to by Xcel defines contiguous as a "single physical customer site or location, as distinct from customer accounts at different geographical locations".[109] It does not provide any clarity as to property lines, easements, roads or utility easements that may run through a ratepayer's campus.

129. The solar law definition of Contiguous should be incorporated in Xcel's Rules.

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[108] 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 (November 30, 2012) at 12.

[109] Ex. 136, Information Request MCC 251.

3. Coincident Peak Billing

130. The rules for Coincident Peak Billing should be expanded to allow this coincident billing for customers taking delivery at two or more service points above the 500KW threshold on contiguous properties.[110]

131. 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.[111]

132. 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.[112]

133. 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

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[110] 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).

[111] Ex. 340, Schedin Direct at 24:8 to 25:5.

[112] Ex. 340, Schedin Direct at 24:8 to 25:5.

result.[113] This solution is not practical nor is it efficient for customers to redesign a system that can be efficiently managed with technology.[114]

134. Setting a threshold 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.[115] 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

135. 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.[116]

136. Concerns stem in part with there being no incentive to manage costs prudently and no penalty if not managed prudently.[117] Xcel therefore, has no incentive to add oversight and risk of no return, delay is good for Xcel.

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[113] Ex. 107, Huso Rebuttal at 43:4-10.

[114] Ex. 342, Schedin Surrebuttal, at 14:6-12.

[115] 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 13.

[116] 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).

[117] 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.

137. There is no deadline or motivation for the Company to move this forward, so the Commission needs to provide one in an order.

138. 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.[118]

2. Peer Benchmarking

139. There are areas of concern with respect to various cost benchmarks of NSPM against its sister companies, as well as peers. 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.[119]

140. The Chamber observed that that there are several areas that Xcel needs to improve significantly as compared to peers and sister companies.[120]

141. The Department agrees that that the Chamber's proposal is appropriate and all costs should be measured.[121]

142. Xcel must 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.

[118] Ex. 345, Maini Surrebuttal at 27:7-13.
[119] Ex. 343, Maini Direct at 43:28 to 44:6.
[120] Ex. 343, Maini Direct at 44:8-16.
[121] Ex. 412, Ouanes Rebuttal at 16:14-20.

III. 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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