Minnesota Public Utilities Commission

Staff Briefing Papers

Volume IV - Sales Forecasting and Class Cost of Service Study

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Meeting Date: March 19, 2015 (Oral Argument)..Agenda Item #__
March 26, 2015 (Deliberations)

Company: Xcel Energy (d/b/a Northern States Power Company)

Docket No. E002/GR-13-868

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

Issues:

1. Should the Commission adopt the weather normalized sales data in the Xcel January 16, 2015 compliance filing for ratemaking purposes?

2. Should the Commission adopt the ALJ's recommendations regarding Xcel's Class cost of service study?

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Relevant Witnesses

1. Weather-Normalized Sales

Xcel – Jannell E. Marks and Karen T. Hyde
Department – Sachin Shah

2. Class Cost of Service Study

Xcel - Michael A. Peppin
Department - Dr. Samir Ouanes
OAG - Ron Nelson
MCC - Kavita Maini
XLI[1] - Jeffry Pollock

Note: Class revenue apportionment and customer charges are not discussed in this volume of the briefing papers.

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[1] XLI (Xcel Large Industrials) is a consortium of the following companies: Flint Hills Resources, Gerdau Ameristeel Corporation, Unimin Corporation and USG Interiors, Inc.

Issue 1: Should the Commission adopt the weather normalized sales data in the Xcel January 16, 2015 compliance filing for ratemaking purposes?

a. Importance of Forecasting and Weather-Normalization

The ALJ discusses the resolved issues relating to sales forecasting in ¶¶645-653 of the report.

A test year sales forecast is necessary to determine revenues at both the current and proposed rates.

It is important that the sales figure in the test year be representative of expected sales in a normal year.[2] If the forecast overestimates sales, rates will be set too low, and the Company will not recover the full cost of service. Conversely, if the forecast underestimates sales, rates will be set too high, resulting in customers paying more than what is necessary to recover the revenue requirement. Thus, in order to set the correct rates, it is important to have a sales forecast that is as accurate as possible.

The weather is probably the most important factor affecting energy sales. Because the weather varies from year-to-year, the sales data fluctuate, sometimes wildly, according to the weather. Test-year sales data should not contain the impact of abnormal weather. If the test-year was characterized by a hotter-than-normal summer, it would contain a sales figure higher than normal because of the higher air-conditioning need. Conversely, if the test-year was cooler-than-normal, the sales of electricity would be understated. The test-year sales forecast should not contain the effects of abnormal weather conditions; it is important to cleanse the sales data of the impact of abnormal weather conditions.

The procedure used to remove the impact of abnormal weather conditions and project the test year sales data allowing for the impact of only "normal" weather is called "weather normalization" and the resulting sales data are called weather-normalized sales.

Xcel sums up the process thus:[3] ". . . the historical weather impact on historical consumption [of electricity] for each class was modeled and the "[f]orecasted sales were then projected by simulating the established statistical relationships over the forecast horizon assuming normal weather."[4] Further, as elaborated by Xcel: "The methodology calculates a weather impact from unusual weather based on weather response coefficients, actual weather, normal weather, and number of customers for each month. The weather impact is then subtracted from actual sales to derive weather normalized sales."[5]

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[2] Hyde Rebuttal at 3.
[3] Marks Direct at 37.
[4] Normal daily weather is calculated based on the average of historical heating-degree days and THI (Temperature-Humidity Index) for the 20-year time period 1993 to 2012. Xcel's method for calculating normal weather using a 20-year period of actual data was accepted by the Commission in previous dockets. See Marks Direct at 38.
[5] Shah Surrebuttal at 13.

The weather normalization process requires the use of weather coefficients which estimate the response of sales of electricity to a unit change in the variables noted in the preceding paragraph.

b. Xcel's Forecast of Weather-Normalized Sales

Xcel claims that, in recent times, the forecasted estimate of sales adopted by the Commission in rate case proceedings has been higher than actually realized.[6] Xcel adds that the projected sales figure approved by the Commission in the previous rate case (E002/GR-12-961) was higher than the Company's actual sales on a weather-normalized basis through the end of August 2013. In the previous rate case, Xcel indicates that the Department challenged the Xcel's sales forecast as too low and advocated a higher sales estimate for the test-year. Xcel notes that this higher forecast adopted by the Commission increased the Company's projected test year retail revenue by $26,163,000.[7] As a result, Xcel claims that the approved sales forecast led to an under-recovery of $18.2 million.[8]

In the previous rate case, the Department challenged not merely Xcel's sales forecast, but also the customer count, future energy prices, loss of large industrial consumers, and the treatment of the effect of demand Side Management (DSM) on energy sales/consumption.

In this rate case, Xcel responded to the Department's concerns raised in the previous rate case. Yet, the Department raised numerous concerns again regarding Xcel's forecast.

Xcel's main concern in this rate case is that the declining sales have to be explicitly reckoned with in the test-year sales figure. Xcel acknowledges that the declining sales are offset by slightly increasing customer count.

Xcel has projected a declining demand for electricity for 2014 and 2015. For the year 2014, total sales are expected to be 30,243,571 MWh, and customer count is expected to be 1,244,540, and for 2015, total sales are projected to be 30,108,800 MWh and customer count is expected to be 1,249,794.[9]

Xcel noted that "[t]he decline in retail sales in 2014 and 2015 is due to declining sales in the Residential and Small Commercial and Industrial classes,"[10] with the residential class accounting for almost 89-percent of Xcel's total customers.

Xcel identified the key factor driving a reduction in energy sales to be "energy efficiency, including both Company-sponsored energy efficiency achievements as well as customer- and market-driven conservation outside of our programs." [11] The Large Commercial and Industrial

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[6] Hyde Direct at 2.
[7] Hyde Direct at 5.
[8] Hyde Direct, at 6.
[9] Marks Direct at 9.
[10] Marks Direct at 13.
[11] Marks Direct at 14.

sector has also been affected by lower sales due in large part to shut downs and also the economic recession.[12]

Xcel claims that DSM initiatives reduce sales over time, and that this reduction must be reflected in the forecast to avoid overstating future sales. Not adjusting for DSM, Xcel claims, overlooks what DSM programs are intended to accomplish.[13] Xcel noted that in the previous rate case, the Department held that DSM was fully embedded in historical sales, and, therefore, no adjustment to future sales was necessary.[14] Xcel insisted that making no adjustment will lead to an over-forecast of sales.[15] But, Xcel noted that rather than debating again in this proceeding whether or not it was appropriate to adjust for incremental DSM and what time period to use to calculate embedded DSM, the Company has utilized a new methodology to account for future DSM.[16] However, upon review of Xcel's new methodology, the Department concluded that its "approach of subtracting estimated DSM effects from sales makes it less certain that the sales forecast will be accurate."[17]

C. The Department's Critique

The Department critically evaluated the statistical models of forecasting used by Xcel and listed several broad concerns with Xcel's modeling of sales data.[18] One concern related to Xcel's use of the price of electricity, the Department arguing that the use of a price variable derived from revenues which are subject to the interim rate mechanism, inflates the price variable, while rate case refunds provide contradictory price information. Additionally, the Department argued that the use of the price variable as a combination of a monthly fixed charge and an energy usage charge, inflates the per-unit price. Notwithstanding these objections, the Department did not recommend that Xcel stop using the price variable in forecasting, nor did the Department cleanse the price variable of the problems and present a "clean" set for the Company's use. Instead the Department recommended that "the Company in the future work with the Department and other stakeholders to determine if the Company can improve [its] price variable or other aspects of [its] sales forecasting models."[19]

With regard to Xcel's incorporation of the DSM impact on sales, the Department noted several concerns, principally concluding that "the Company's approach of subtracting estimated DSM effects from sales makes it less certain that the sales forecast will be accurate."[20] The Department concluded that "the appropriate approach, which does not introduce uncertainty in the DSM adjustment, is by using the billing month data that already encompasses any embedded DSM."[21]

The Department noted, citing the Commission's September 3, 2013 Order in the 12-961 case, that the Commission has stated that DSM adjustment would understate test-year sales and that DSM

[12] Marks Direct at 15.
[13] Hyde Direct at 5.
[14] Marks Direct at 31.
[15] Marks Direct at 32.
[16] Marks Direct at 32-33.
[17] Shah Direct at 13.
[18] Hyde Direct at 8.
[19] Shah Direct at 11.
[20] Shah Direct at 13.
[21] Shah Direct at 17-18.

efforts are already reflected in the sales data. The Department also indicated that the Commission has stated that the DSM savings are levelling off, rather than increasing. The Department also noted that, in the September 3, 2013 Order, the Commission did not approve DSM adjustment to the sales forecast.

In light of the Department's objections, the Department made what it called preliminary adjustments to Xcel's sales for the test-year – an increase roughly of $29 million.[22]

D. MCC's Critique

Intervener MCC, too, expressed concern about the Company's sales forecast, arguing that because the historical data on DSM achievements is derived from energy savings in the Conservation Improvement Program (CIP) plan, the Company was being compensated for energy efficiency twice – once through the CIP incentive and then, again, in lower sales caused by energy efficiency.9[23]

E. Resolution of Sales Forecasting and Weather-Normalization

In the rebuttal testimony, Xcel prepared an updated forecast. Xcel indicated that its initial forecast "was developed in July 2013 based on actual sales and customer count information through June 2013" and that Xcel has, since then, included "[eleven] 11 additional months of actual data, through May 2014."[24] Xcel also showed that, with respect to the previous rate case, "[w]eather-normalized 2013 actual retail sales through August [2013] were significantly lower than the final sales forecast approved for the 2013 test year (-313,913 Mwh or -1.5 percent)."[25]

The updated forecast reflects total retail sales of 30,468,251 MWh in 2014, which is 224,680 MWh higher (0.7 percent) than the initial forecast. The updated forecast projects retail customer count to average 1,250,030, which is 5,489 customers or 0.4 percent higher than the Company's initial forecast.[26] The updated sales forecasts exceed the initial forecasts for all customer classes except large commercial & industrial, street lighting and interdepartmental sale to the gas operations of Xcel. Xcel added: "Weather normalized actual sales in all classes are lower than forecast. The estimated year-to-date revenue impact of the MWh variance from the approved forecast for total retail sales is -$18,205,683."[27] As to the future, Xcel maintains that while the recovering economy would improve sales, it would be subject to the countervailing "effects of Company-sponsored DSM programs, market- and government-driven efficiency gains, increasing electricity prices and continued weakness in the Large Commercial and Industrial sector."[28]

Notwithstanding the updated initial forecast of sales and customers, Xcel indicated an alternative to the updated forecast to resolve the disputes surrounding adjustment for DSM and weather normalization.

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22 Shah Direct, at 3.
23 ALJ's Report para 648, p. 149.
24 Marks Rebuttal at 2.
25 Marks Direct at 18.
26 Marks Rebuttal at pp. 2-3.
27 Ibid.
28 Marks Direct at 19.

Xcel noted that in order to completely eliminate the disputes relating to DSM-related adjustment to sales forecast, it recommended that the Commission adopt weather-normalized actual, rather than forecasted, data for the test year to set rates in this proceeding.[29] Xcel stated that it would provide all the "work done to convert actuals to weather-normalized actuals" in a compliance filing later.[30]

The Department agreed that the use of actual 2014 data would lessen the uncertainty associated with identifying the adjustments for DSM and predicting how the economy would perform during the rest of the test year.[31] The Department accepted this latter proposal of using weather-normalized actual data for 2014. The Department observed:

> . . . since the record already includes five months of actual data, January through May 2014, the company only needs to provide an additional six months of actual data on December 16th, 2014. Specifically, Ms. Marks, in her rebuttal testimony, Exhibit JM-2, Schedules 1through 6, provided the first five months of actual 2014 data and calculations.[32]

MCC, too, accepted the Company's proposal.[33]

No other party commented on the sales forecast issue.

ALJ's Recommendation

The ALJ summed up her recommendation in ¶ 653:

> 653. As explained by Company witness Jannell Marks, weather-normalized actual 2013 sales were significantly lower than the forecast approved by the Commission in the last case. Weather-normalized actual 2013 sales were 0.3 percent higher than the Company's forecast. In this case, to avoid the significant under-recovery of a forecast set too high, or an over-recovery if the forecast were set too low, the parties have agreed to use weather-normalized actual sales. Thus, it is reasonable to adopt the sales forecast proposal agreed to by the Company, the Department, and MCC.

Xcel's Compliance Filings

On December 16, 2014, Xcel submitted its first compliance filing documenting the actual electric sales and customer data by major customer class for January through November 2014. In this filing, Xcel retained the December 2014 weather-normalized sales data from the rebuttal testimony of Marks. Xcel indicated that the weather-normalization calculations used the Department's coefficients (as agreed at the August 11, 2014 evidentiary hearing in this case).[34]

[29] Hyde Rebuttal at 1; Marks Rebuttal at 10.
[30] Hyde Rebuttal at 6.
[31] Shah Surrebuttal at 4.
[32] Hearing Tr., Vol 4, 52: 3-10.
[33] ALJ's Report, para 652, p. 149.
[34] The Department opposed the use of Xcel's calculations and coefficients in the weather normalization of energy sales because of Xcel's tendency to adjust the sales data to capture the effect of DSM measures. The Department concluded: ". . . the calculations and coefficients that should be used are those in the Department's regression models;

Xcel noted that it would submit sales, customers and present revenue based on weather-normalized actual data for the full 2014 test year by January 16, 2015.

On January 16, 2015, Xcel filed the weather-normalized actual electric sales and customer data by major class for January through December 2014 and also a comparison with the forecast of the same variables provided in the rebuttal testimony.

The table below provides a comparison of the actual sales with the previous forecast:[35]

2014 Test Year Sales (Mwh)				
	Weather Normalized Actual Sales Jan-Dec 2014	Updated Forecast Jan-Dec 2014 (Marks' Rebuttal)	Difference: Actuals less Updated Forecast	% Difference Between Actuals and Updated Forecast
Residential without Space Heat	8,366,146	8,210,633	155,514	1.9%
Residential with Space Heat	396,824	390,125	6,699	1.7%
Small Commercial & Industrial	13,605,514	13,361,206	244,308	1.8%
Large Commercial & Industrial	8,179,537	8,282,742	-103,205	-1.2%
Public Street & Highway Lighting	143,362	141,919	1,443	1.0%
Other Sales to Public Authority	66,823	73,556	-6,733	-9.2%
Interdepartmental	11,228	8,070	3,158	39.1%
Total Retail	30,769,436	30,468,251	301,184	1.0%

As can be seen from this table, Xcel's total actual weather-normalized retail sales for January-December are 1.0 percent higher than the updated forecast for January-December 2014 noted in the Rebuttal Testimony.

the Department's calculations and coefficients used only billing month data, with no incremental or future DSM adjustments." See Shah Surrebuttal at 14.

[35] Source: Xcel's January 16, 205 Compliance Filing, Attachment A, page 1 of 1.

The table below provides a comparison of the actual average customers with the previous forecast:[36]

2014 Test Year Average Customers				
	Actual Customers Jan-Dec 2014	Updated Forecast Jan-Dec 2014 (Marks' Rebuttal)	Difference: Actuals less Updated Forecast	% Difference Between Actuals and Updated Forecast
Residential without Space Heat	1,081,230	1,081,226	4	0.0%
Residential with Space Heat	32,357	32,299	58	0.2%
Small Commercial & Industrial	129,939	129,891	48	0.0%
Large Commercial & Industrial	438	447	-9	-2.0%
Public Street & Highway Lighting	4,081	4,070	11	0.3%
Other Sales to Public Authority	2,090	2,089	1	0.0%
Interdepartmental	11	10	1	10.0%
Total Retail	1,250,146	1,250,030	116	0.0%

For the test year 2015, Xcel reported total weather normalized sales of 30,785,036 Mwh, compared to the 30,769,436 Mwh for test year 2014 – an increase in sales of 15,600 Mwh. The customer count for 2015 is one higher than the count of 1,250,146 for 2014. Xcel indicated that the "December 16th sales true-up and January 9th ALJ financial schedule filings inadvertently did not capture the estimated sales from a new large commercial and industrial sales customer in 2015" and that those estimated sales are now included in the January 16, 2015 compliance filing. Xcel added that the adjustment related to this new customer was agreed upon by the Company and the Department.

Response of Other Parties

No party commented on the sales data filed by Xcel in the January 16, 2015 compliance filing.

Options

A. Adopt the weather-normalized sales data in the January 16, 2015 compliance filing for rate-making purposes.

B. Adopt the weather-normalized sales data in the Xcel rebuttal testimony for rate-making purposes.

C. Adopt the Department's sales forecast in Shah's surrebuttal testimony.

(Note: These decision alternatives correspond to alternatives IV, A (1 through 3) on p. 27 of the deliberation outline.)

[36] Source: Xcel's January 16, 205 Compliance Filing, Attachment A, page 1 of 1.

Staff Recommendation

Staff recommends **Option A**.

Issue 2: Should the Commission adopt the ALJ's recommendations regarding Xcel's Class cost of service study?

A. Xcel's Cost Study and its Purpose - Introduction

The Class Cost of Service Study (CCOSS) study breaks down a utility's total revenue requirement into its constituent customer class responsibility. For example, in Xcel's initial testimony, the total revenue requirement was established to be roughly $2.9 billion for the test year 2014. Through the CCOSS, this amount is allocated, on a cost-causative basis, between the customer classes, as shown in row [11] below:

Table 1[37]

	ADJUSTED COST RESPONSIBILITIES: 2014 TEST YEAR ($000)					
		Total	Resid	Non-Demand	Demand	Street Ltg
[11]	Adjusted Rate Revenue Reqt (line 1 + line 10)	2,882,943	1,062,408	109,706	1,687,321	23,507
[12]	Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 - line 23)	356	264	16	75	1
[13]	Adjusted Operating Revenues (line 11 + line 12)	2,883,299	1,062,672	109,723	1,687,397	23,508
[14]	Present Rates (line 4)	2,713,836	983,255	101,372	1,603,455	25,753
[15]	Adjusted Deficiency (line 13 - line 14)	169,463	79,417	8,350	83,941	(2,245)
[16]	Defic / Pres Rates (line 15 / line 4)	6.2%	8.1%	8.2%	5.2%	-8.7%

The purpose of a CCOSS is to target a certain amount of revenue to be received from each customer class. In the actual setting of rates, however, factors other than costs play a role, often a more important role.

The row marked [14] in the above table shows the revenues received presently from each class of customers. A comparison of the costs, row [11], with the revenues for each class of customers will show if any category of customers is subsidized, and if so, to what extent, by other classes of customers.

It is in the nature of public utilities that costs are often shared between services.[38] This is because the facilities that enable the production of one good also, simultaneously, enable the production of another good. For example, the generation capacity of an electric utility installed to meet peak-load also serves "jointly" the base load demand. Another aspect of costs is that they are often common to all services supplied by a utility – e.g., overhead costs like management costs are

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[37] Results of Xcel's cost study. See Peppin Rebuttal at 4. Summary results for the 2015 cost study are at p. 5 of Peppin Rebuttal.

[38] Peppin Direct, Exhibit MAP-1, Schedule 2, page 2 of 11.

"common" to multiple functions, such as distribution, transmission and generation. The task of a cost study is to find "allocators" that distribute these joint and common costs across service categories (residential, industrial, and so on) in a cost-causative manner.

The construction of a CCOSS then involves three key steps.

First, the utility's investments and expenses are functionalized – that is, arranged according to the major function. The major functions are production, transmission and distribution. The purpose of functionalizing costs is to aid in determining which customers are jointly or solely responsible for various costs.[39]

After distributing the investments and expenses between these three functions and sub-functions, they are classified between demand-related (or capacity-related), energy-related, or customer-related aspects. Here again allocators (percentages) are used to separate joint and common costs.

This second step is called classification. Xcel uses a procedure called stratification to separate generation costs related to the capacity-function from costs related to the energy-function.[40] Xcel uses a procedure called Minimum Distribution System to separate the distribution costs between capacity-related and customer-related functions.

The following Table 2 summarizes Xcel's functionalized costs and their classification:

Table 2[41]

Function/Sub-Function	**Cost Classification**		
	Demand	**Energy**	**Customer**
Summer Capacity-Related Fixed Generation	X		
Winter Capacity-Related Fixed Generation	X		
Energy-Related Fixed Generation		X	
Off-Peak Energy (Fuel and Purchased Energy)		X	
On-Peak Energy (Fuel and Purchased Energy)		X	
Transmission	X		
Distribution Substations	X		
Primary Transformers	X		
Primary Lines	X		X
Secondary Lines	X		X
Secondary Transformers	X		X
Service Drops	X		X
Metering			X

39 Nelson Direct at 3.
40 Peppin Direct Testimony, Exhibit MAP-1, Schedule 2, page 4 of 11.
41 Peppin Direct, Exhibit MAP-1, Schedule 2, page 5 of 11.

Customer Services			X

The third step in a CCOSS involves choosing appropriate allocators in allocating the classified costs to the appropriate customer classes on a cost-causative basis. Customer costs are costs associated with the customer regardless of the energy consumed and are allocated based on the number of customers; demand (or capacity) costs are driven by the need to meet peak demand and each class' contribution to peak demand drives this allocator; and energy costs are caused by the amount of energy consumed and are allocated based on each class's energy consumption.
In some cases, the costs are obvious and are directly allocated. In instances where the costs are shared by the functions (joint and common costs[42]), they are assigned using allocators that take into account the functionalized and classified features, in other words, particular attributes of service that indicate what drive the costs.

Table1 at the top of this section summarizes the end result of the cost study. "The end result [of a cost study] is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class' share of the capacity, energy and customer service requirements."[43]

The cost responsibility noted above in Table 1 can then be compared with the actual rates proposed by Xcel – that is, the proposed revenue responsibilities. Table 3 below presents the revenue responsibilities.

Table 3[44]

2014[45] PROPOSED REVENUE RESPONSIBILITIES ($000)

	Total	Resid	Non-Demand	Demand	Street Ltg
[18] Proposed Rates (CCOSS page 3, line 3)	2,882,943	1,057,937	109,202	1,690,051	25,753
[19] Incr Misc Chrgs & Late Pay (CCOSS page 7, line 21 to line	356	264	16	75	1
[20] Proposed Operating Revenues (line 18 + line 19)	2,883,299	1,058,201	109,218	1,690,126	25,754
[21] Proposed Increase (line 20 - line 14)	169,463	74,946	7,846	86,671	1
[22] Difference / Pres (line 21 / line 14)	6.2%	7.6%	7.7%	5.4%	0.0%
[23] **Ratio: Class % / Total %**	**1.00**	**1.22**	**1.24**	**0.87**	**0.00**

The row marked [18] in Table 3 above provides the revenues proposed to be collected from the different customer classes. A comparison of **this row** with the **row marked [11] in Table 1** shows that Xcel's proposed revenues are very closely aligned with the costs estimated by Xcel.

42 For example, the facilities required to meet peak-load also serve to meet base-load demand. Here, the facilities enable joint production of two services and the costs have to be allocated between them by some method. Some costs are common between services -- management costs are overhead costs which are common to the functions of generations, transmission and distribution and have to be distributed among the numerous services for which the costs are common.

43 Peppin Direct, Exhibit (MAP-1), Schedule 2, page 2 of 11

44 Peppin Rebuttal, Exhibit MAP-2, Schedule 1, page 1 of 1.

45 Xcel filed a cost study for the teat year 2014 and another cost study for 2015 reflecting the revenue requirement for the year 2015. Xcel explained that the 2015 CCOSS is essentially the same as the 2014 CCOSS, except it includes an additional $98.4 million of revenue requirements that reflect the 2015 step increase.

A consequence of this comparison is that if the cost study is proven to be biased or prejudiced, it would support a rate design that is arguably inefficient and/or unfair.

Xcel notes, in numerous places throughout the pre-filed testimony, that it is open to suggestions for refining its cost study in the future.

B. Parties' Response to Xcel's Cost Study – Broad Overview

The Department, the OAG, XLI, and MCC have raised numerous objections, or suggested modifications, to Xcel's cost study. In this section a very broad overview is given of the parties' main perception of Xcel's cost study.

a. Department

In general, the Department argues that Xcel's cost methodology has allocated more of the revenue requirement to the residential class than necessary and that Xcel has incorporated changes to the cost methodology that are inconsistent with the Commission's orders in previous rate cases.

b. OAG[46]

In general, the OAG argues that Xcel attempts to use the cost study "to justify increasing its revenue allocation for the residential and C&I Non-Demand customer classes . . . , while reducing the allocation to its other customer classes."[47] The OAG notes that it has "identified several ways that Xcel's improper methodology and subjective decision-making has resulted in inaccurate results in its CCOSS. Fixing these errors would result in a CCOSS that shows that, absent any need for an overall revenue increase, the residential and C&I Non-Demand classes currently each pay their cost of service, if not more."

In the classification of plant functionalized as belonging to the distribution system, the OAG maintains that specific accounts of plant, containing both demand and customer costs, have been misclassified by Xcel. The OAG notes that misclassification "can have a significant impact on the CCOSS, since the residential class can pay more than 95% of the costs classified as customer costs, but less than 35% of the costs classified as demand costs."[48]

The OAG insists that Xcel's classification of these accounts uses analytical methods that overestimate the customer costs of each account and correspondingly and underestimate capacity costs. The OAG suggests modifications to Xcel's cost study for the future, but, for now, the OAG recommends that the Commission order adjustments to counterbalance the inherent over-classification of customer costs in Xcel's analysis.[49] The OAG recommends that the Commission order Xcel to re-classify and allocate an additional 10-percent of the distribution costs as capacity costs, and correspondingly reduce the customer costs by 10-percent, within each of its minimum system analyses.

c. MCC

MCC argues that Xcel and the Department support use of a cost method which results in classifying significant portions of fixed production plant as energy related.[50] MCC also charges

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[46] AARP filed a brief supporting the OAG's recommendations regarding the CCOSS. ALJ's finding ¶ 674.
[47] OAG Post-Hearing Brief at 45.
[48] OAG Post-Hearing Brief at 46.
[49] OAG Post-Hearing Brief at 54.
[50] MCC Post-Hearing Brief at 10.

that Xcel uses an overall method that drives more cost to commercial and industrial rates than in other jurisdictions and is resulting in significant departures of large employers from Minnesota.

d. XLI

XLI is generally supportive of Xcel's cost study but recommends two modifications concerning Xcel's stratification procedure and a change in the reflection of the value of capacity .

C. Disputed Class Cost of Service Study Issues

The ALJ (¶ 675, pp. 154-155) identified the following issues as unresolved between the parties:

i. The Classification of Fixed Production Plant;

ii. The Classification of the Costs of Company Owned-Wind Facilities;

iii. Updating of Fixed Production Plant Cost Data;

iv. Use of the D10S Capacity Allocator;

v. Allocation of Other Production Operation and Maintenance (O&M) Costs;

vi. The Use of the Minimum Distribution System;

vii. Allocation of Economic Development Discounts; and

viii. Allocation of Interruptible Rate Discounts.

C. i. The Classification of Fixed Production Plant

a. Plant Stratification Method versus Straight Fixed Variable Method

Introduction: Xcel's Plant Stratification Method

After functionalizing costs between generation, transmission and distribution, the fixed generation costs are separated between capacity-related costs and energy-related costs.

The method by which Xcel separates the fixed production costs between capacity- and energy-related costs is called plant stratification. Capacity (or demand) costs vary with the KW demand imposed by the customer and energy costs vary with the kWh that the utility provides.

Xcel's method supposes that generation is meant to serve the needs of both demand (capacity) and energy. The "capacity-related" portion of the fixed costs of Company-owned generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost).[51]

In the following Table 4,[52] the typical demand cost of a peaking plant is $770 and costs up to this figure in other types of plants are stratified (or allocated or classified) as demand-related costs. Costs exceeding this threshold value are assigned to the energy function.

Table 4[53]

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%

Xcel calculates the capacity-related portion of fixed costs based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable combustion turbine peaking plant. For example, in the case of an exclusively peaking plant, the replacement value per kW is taken to be $770. Here, the proportion of cost assigned to capacity is all of the $770 (100-percent). In the case of a nuclear plant, the replacement value per kW is taken to be $3,689 and the portion related to the capacity function is $770/$3,689 (21-percent) and the remaining portion, 79-pecernt, is assigned to the energy function. Likewise, for the hydro plant, the replacement value is $4,519 per kW. Out of this $770 is allocated to the capacity function (17-percent), while the remainder, 83-percent, is assigned to the energy function. In general,

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[51] The ALJ concluded that the "capacity-related costs are based on the cost of a comparable combustion turbine (CT) peaking plant, which is built at the lowest capital cost and highest operating cost, to serve customer demand when there are no lower cost resources available (i.e. during times of peak demand)." See ¶ 677, p. 155, ALJ's Order.

[52] Peppin Direct, p. 13.

[53] Source: Peppin Direct, Exhibit (MAP-1), Schedule 2, Page 4 of 11

generation costs up to the costs of a peaking plant are classified as demand-related, while the costs in excess of that are classified as energy related.

Xcel's plant stratification methodology is also called the Equivalent Peaker method and this is the same process, albeit with some refinement, that Xcel has used with Commission approval since the late 1970s.

Parties' Position

MCC

As in prior rate cases, MCC recommends that Xcel adopt the Straight Fixed Variable method instead of Plant Stratification to classify fixed production plant.

MCC's main concern is that Xcel's classification of portions of fixed production plant as energy results in the recovery of these costs through energy charges.

The more energy (kwh) a customer class consumes (and large industrial customers consume more energy), the more it will pay towards recovery of the generation costs. MCC finds it anomalous that generation costs ought to be recovered through a Kwh charge when Xcel has predicted declining sales and that this proposal will result in lower cost-recovery. Further, MCC argues that customer classes that use less energy but contribute more towards system peak demand will not get their fair share of cost allocated to them or pay for these costs as these fixed production costs represent the capacity used to serve the purpose of meeting system peak demand and planning reserve margin requirements.[54]

MCC recommends a procedure called the peak demand or straight fixed variable method.

Under this method, all fixed production plant is classified as demand-related based on the notion that the plant capacity is required to meet both peak demand and reserve margin requirements. These are costs incurred in direct relationship to the MWs of demand that customers place on the system and 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, but the cost of the fixed plant capacity should be assigned to customers on the basis of their demand.[55]

MCC presented[56] the following Table 5 to contrast the two methods of classifying generation costs. In MCC's methodology, generation costs are all assigned to demand and none to energy – which shifts cost responsibility from large commercial/industrial customers to smaller residence and commercial non-demand customers.

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[54] Maini Direct at 17.
[55] MCC Post-Hearing Brief at 16.
[56] Maini Direct at 20.

Table 5

Customer Class	[1]	[2]	[3]	[4]	[5] = [3] - [1]	[6] = [4] - [2]
	Proposed CCOSS		**Straight Fixed Variable 1CP**		**Change Vs Proposed CCOSS**	
	Adjusted Deficiency Line [15] of Exhibit ___(MAP-1), Schedule 3	**Defic / Pres Rates** Line [16] of Exhibit ___(MAP-1), Schedule 3	**Adjusted Deficiency** Line [15] of Attachment A	**Defic / Pres Rates** Line [16] of Attachment A	**Adjusted Deficiency**	**Defic / Pres Rates**
Residential	$92,566	9.2%	$111,753	11.2%	$19,187	1.9%
Commercial Non Dmd	$7,766	7.4%	$9,101	8.6%	$1,334	1.3%
C&I Demand	$94,699	5.7%	$75,661	4.6%	($19,038)	-1.2%
Lighting	($2,322)	-8.8%	($3,806)	-14.4%	($1,484)	-5.6%
Total	$192,709	6.9%	$192,709	6.9%	$0	0.0%

Note: Under the fixed variable method, all fixed production costs such as plant investment and fixed O&M costs are classified as capacity-related and allocated to classes with a demand allocator (D10S). The "adjusted deficiency" in column [1] is taken from row 15 of Table 2, Peppin Direct, p. 6.

As can be seen from Table 5 above, comparing columns 1 and 2 (Xcel-proposed) with columns 3 and 4 (MCC proposed), under the SFV approach, more of the cost responsibility (and more of the rate increase) is shifted to the residential customers.

Department

The ALJ captured the Department's position in ¶ 680 of her Report:

> The Department asserted that the Plant Stratification method properly shows the dual value of baseload plants and is consistent with the goals of least cost planning and cost savings. If the Company acquired production plants only to meet peak capacity needs at the lowest cost, the Company would be building only peaking generators, at the lowest cost per unit of capacity. Instead, the Company chooses a mix of generation facilities of varying capital costs to attain the dual goals of sufficient capacity and viable energy costs.

ALJ's Conclusion

The ALJ discusses this issue in ¶¶ 676-681, pp. 155-156.

In **¶ 678**, the ALJ summarizes MCC's position:

> As in prior rate cases, MCC recommended that the Company adopt the Straight Fixed Variable method instead of Plant Stratification to classify fixed production plant. The Straight Fixed Variable method classifies all fixed production plant costs as demand-related because plant capacity is required to meet peak demand and reserve margin requirements. Variable costs such as fuel align with energy consumption and are

> therefore classified as energy-related. MCC argued that the Straight Fixed Variable method should be used based on its view that high energy users, such as large customers, are allocated more than their share of costs under the Plant Stratification method. MCC made this same argument in the last rate case. [Footnotes deleted]

The ALJ's conclusion (without footnotes) is noted in **¶ 681**:

> In several past rate cases, the Commission has compared Plant Stratification to the Straight Fixed Variable method, and determined that Plant Stratification is the more reasonable method to classify fixed production plant costs. MCC has put forward no new convincing argument to show that the Straight Fixed Variable method should be substituted. Nor has MCC responded to the Commission's emphasis on the need to recognize the dual nature of base load plants. For these reasons, the Administrative Law Judge concludes that the Company's continued use of the Plant Stratification method is reasonable.

MCC's Exception to the ALJ's Finding and Recommendation

MCC argued in its Exceptions that the ALJ failed to recognize that MCC explained differences in Xcel's generation mix for the change in allocating Fixed Production Plant from the Equivalent Peaker method to Straight Fixed Variable method.

MCC emphasized that Xcel's generation mix is changing and now includes more than 1000 MW of wind generation and an additional 750 MW of wind generation approved by the Commission last year.

MCC further pointed out that because wind generation typically produces more output in the off peak hours, sending signals to discourage off peak usage and at the same time adding generation that produces more off peak usage is counter-productive and that, as resources get added for policy reasons, the equivalent peaker theory of the dual nature of resources to serve energy and demand needs no longer holds. These generation resources, MCC reiterated, are being added for reasons other than reliably serving energy or capacity needs and that the changing generation mix warrants changing Xcel's allocation method from the equivalent peaker method to the straight line variable method.

As a result, MCC concludes, the ALJ arrived at the wrong conclusion. MCC asks that the following language be appended to the ALJ's finding in ¶ 678:

> <u>In this case MCC further explained the changes in Xcel's generation mix and driving factors in making generation decisions as well as changes in ratepayer usage. All of MCC's identified changes support changing the method Xcel uses for allocation.</u>

MCC also recommends the following change to ¶ 681:

> ¶ 681 In several past rate cases, the Commission has compared Plant Stratification to the Straight Fixed Variable method, and determined that Plant Stratification is the more reasonable method to classify fixed production plant costs. MCC has put forward ~~no~~ new

> convincing arguments to show that the Straight Fixed Variable method should be substituted. ~~Nor has~~ MCC responded to the Commission's emphasis on the need to recognize the dual nature of base load plants. For these reasons, the ~~Administrative Law Judge concludes that the~~ Company's ~~continued~~ use of the Plant Stratification method ~~is reasonable.~~ should be changed to the Straight Fixed Variable method.

Options

C. i. a. 1 Adopt the ALJ's conclusion.

C. i. a. 2 Adopt the position taken by MCC in its Exceptions.

(Note: These decision alternatives correspond to alternatives IV, B, 1 (a and b) on p. 27 of the deliberation outline.)

C. i. The Classification of Fixed Production Plant

b. Proposed Modifications to the Plant Stratification Method

Introduction

The ALJ's Report, ¶ 685, found:

> Under the existing Plant Stratification method, the Company compares the current-dollar replacement value of a peaker with the current-dollar replacement cost of the other types of plants to arrive at the capacity-related and energy-related stratification allocation for each plant type.

XLI identifies two flaws in Xcel's analysis – (1) Xcel's use of current replacement value of its existing gas turbine and diesel plants and (2) Xcel's use of undepreciated replacement value. XLI proposes to revise the Plant Stratification calculation in two ways:[57] 1) to replace the current-dollar replacement value of a peaker with the estimated cost of a new peaking plant[58] and 2) replace current-dollar replacement costs for each plant type with depreciated replacement values.

XLI argues that the threshold value of $770 in Table 4 (preceding) is the current replacement value of Xcel's gas turbine and diesel plants. But, MCC points out, this value is not the replacement cost that Xcel would incur to install a new peaking unit which XLI estimates to be $696 per kW (which figure XLI notes Xcel used in the Windsource program).[59] XLI also argues that rates are not set using undepreciated investment and, therefore, cost classification should be based on depreciated replacement value.

[57] Xcel Post-Hearing Brief at 132-133.
[58] As used by Xcel to calculate the Windsource capacity credit.
[59] Pollock Direct at pp. 34-35.

To correct the second flaw, XLI recommends using net depreciated cost as a better measure of the value of capacity.

Accounting for these alleged flaws, the stratification allocation for each plant type would be calculated by comparing the cost of a new, undepreciated peaking plant (using the price from the Windsource docket) to the depreciated replacement value of the other plant type (nuclear, fossil, combined cycle, etc.)

XLI provided the following percentage allocation factors derived by using the depreciated replacement value of generation plant.

Table 6[60]

Stratification Allocation by Plant Type
Using Depreciated Replacement Value

Plant Type	Depreciated Replacement Value ($/kW)	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$696	$696÷$696	100.0%	0.0%
Nuclear	$1,456	$696÷$1,456	47.8%	52.2%
Fossil	$759	$696÷$759	91.8%	8.2%
CombinedCycle	$808	$696÷$808	86.2%	13.8%
Hydro	$3,670	$696÷$3,670	19.0%	81.0%

XLI argues that the use of current net replacement costs will send a stronger price signal by recognizing the impact that capacity additions will have on rates.

Calculating the allocation percentages between demand (capacity) and energy based on the depreciated replacement value/kw, in comparison with calculating the same as Xcel has done (replacement value), reduces the proportion of cost allocated to energy and correspondingly increases the proportion allocated to capacity.

XLI recommends that the plant stratification analysis be based on depreciated replacement value, as shown in Table 6 above, and that those percentages be used to develop the stratification percentages in Xcel's class cost-of-service study in this case.

Xcel's Response to XLI's Proposed Adjustments

Xcel indicates that XLI's analysis inappropriately mixes depreciated and non-depreciated costs because XLI begins with the peaking plant costs used by Xcel to calculate the Windsource capacity credit which relate to the cost Xcel would incur to install a new peaking plant on a brown-field. Xcel notes that XLI then compares the cost of a new peaking plant (i.e. not

[60] Pollock Direct at 35.

depreciated) to the "depreciated replacement value" (or embedded cost) of the other plant types. Xcel objects to this comparison as inappropriate.[61]

Xcel concludes that XLI's methodology would shift a significant portion of fixed production costs to the capacity component.[62]

Xcel asks that the Commission disregard XLI's proposed adjustments.

Department and OAG

The ALJ captured the agencies' position thus (footnotes deleted):

> 689. The Department agreed with the Company that XLI's method would inaccurately compare the cost of installing a new peaking unit with all other plants' depreciated replacement value, overstating the relative investment cost of peaking capacity. The OAG also opposed XLI's proposed changes to the Plant Stratification methodology for similar reasons.

ALJ's Analysis and Recommendation

The ALJ discusses this issue in ¶¶ 682-690, pp. 156-158.

The ALJ concluded:

> 690. The Administrative Law Judge concludes that XLI's proposed changes to the Plant Stratification methodology are not reasonable. As explained by the other parties, comparing the cost of a new peaking plant to the depreciated value of other types of generating plants, as XLI has recommended, is not analytically sound.

XLI's Exception to the ALJ's Conclusion

XLI maintained that plant stratification analysis should be based on depreciated replacement value, and that XLI's proposed modifications to the CCOSS were consistent with cost causation principles and yielded a more just and reasonable allocation to the C&I Demand class. As a result, XLI respectfully requested that the Commission reject the ALJ's recommendation in paragraph 690 of the ALJ's Report in favor of adopting XLI's proposed modifications to Xcel's CCOSS.

Options

C. i. b. 1 Adopt the ALJ's conclusion in **¶ 690**.

C. i. b. 2 Adopt XLI's position and recommendation as stated in XLI's Exceptions.

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[61] Peppin Rebuttal at 11.
[62] Peppin Rebuttal at 12.

(Note: These decision alternatives correspond to alternatives IV, B, 2 (a and b) on p. 27 of the deliberation outline.)

C. ii. The Classification of Nobles and Grand Meadow Wind Facilities' Costs

Introduction

The ALJ observed in ¶ 691, p. 158, there are four Xcel-owned wind generation projects included in Xcel's cost study:

(1) Grand Meadow;
(2) Nobles;
(3) Pleasant Valley; and
(4) Border Winds.

The costs of Grand Meadow and Nobles are included in the 2014 CCOSS and in the 2015 Step CCOSS. The costs of Pleasant Valley and Border Winds are only included in the 2015 Step (Rebuttal Testimony) CCOSS.[63]

The Grand Meadow and Nobles projects are older projects and were included in Xcel's last rate case. In that case, Xcel classified the Grand Meadow and Nobles wind generation plants on the same basis as other fixed production plant costs, that is, by the application of the Plant Stratification (or the Equivalent Peaker) method. As a result, these wind plants were classified as about 4 to 5 percent capacity-related and 95 to 96 percent energy- related.

In the instant rate case, however, Xcel has changed its analysis of Grand Meadow and Nobles and has classified these two wind facilities as 100 percent capacity. Xcel has, however, continued to apply the traditional plant stratification method to the Pleasant Valley and Border Winds facilities.

Xcel now argues that these two wind farms **should not** be classified according to the Plant Stratification Method or the Equivalent Peaker method because, first of all, they were added to the Company's system in order to comply with the 2007 Renewable Energy Plan,[64] not to meet energy or capacity needs.

Xcel claims that the plant stratification method does not apply here and a separate classification and allocation approach should be thought of for classifying the Nobles and Grand Meadow plant.

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[63] Peppin Rebuttal at 16. Pleasant Valley and Border Winds are new projects that are expected to be on-line by the end of 2015.

[64] In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for the Grand Meadow Wind Farm, Docket No. E002/CN-07-873, ORDER (Dec. 24, 2007); In the Matter of the Petition of Northern States Power Company, a Minnesota Corporation, for Approval of Investments in Two Wind Power Projects: 200 MW Nobles Wind Project and 150 MW Merricourt Wind Project, Docket No. E002/M-08-1437, ORDER APPROVING INVESTMENTS AND EXPENDITURES, FINDING THE NOBLES PROJECT EXEMPT FROM OBTAINING A CERTIFICATE OF NEED, AND ADDING REQUIREMENTS (June 10, 2009)). See Xcel Initial Brief at 133-134.

Xcel points out that plant stratification was designed to recognize that peaking plants (with low capital costs and high operating costs) are built to serve customer demand when there are no lower cost resources available and that intermediate and baseload generation resources (with higher capital costs) are added to provide low-cost energy. By selecting an optimal mix of these resources, total system costs are minimized. Xcel argues that Nobles and Grand Meadow wind farms "do not fit within this equation."[65]

Xcel also raises a countervailing argument that the proposed classification of Nobles and Grand Meadow capacity (301.5 Mw) costs as totally capacity-related would serve to offset nearly 600 Mw of wind energy that is provided by PPAs, the costs of which are recovered through fuel cost charge.

Parties' Position

Department

The Department argues that in the past three rate cases, Xcel had classified and allocated Company-owned wind farms on the basis of the stratification methodology, under which generation costs were determined to be 4 to 5 percent capacity-related and 95 to 96 percent energy-related.

The Department notes that in comparison to peaking facilities, which are brought on-line to fulfill capacity needs and are thus classified as demand-related, wind facilities can only generate electricity when the wind permits. The Department concludes that energy utilities would not acquire wind generation as a means to ensure sufficient capacity because wind facilities can only generate electricity when the wind is blowing.

The Department notes that the offset argument advanced by Xcel is inappropriate and that if the recovery of costs associated with wind energy are in error, Xcel should pursue "that issue through the appropriate channels."[66]

The Department further notes that Xcel itself had admitted in the past that "the stratification method appropriately classifies and allocates wind generation"[67] and the Commission too has ruled that "Xcel's attribution of wind-facility costs primarily to energy needs closely matches the characteristics of wind facilities. Wind resources by and large replace other energy resources, and contribute very little to capacity."[68]

The Department recommends that Xcel classify the costs of the Nobles and Grand Meadow wind farms on the same basis as the other production plant costs via the plant stratification method.

[65] Peppin Direct at p. 27.
[66] Ouanes Direct at p. 24.
[67] Ouanes, Direct at. 25.
[68] Ouanes Direct at 26.

OAG

The OAG argues that classification of Xcel-owned wind generation facilities as demand-related is inappropriate and recommends classifying all Company-owned wind projects as 100-percent energy-related and allocating associated costs using an energy allocator, not a demand allocator.

If the Commission does not require the classification of Nobles and Grand Meadow as 100-percent capacity-related, the OAG would support the use of plant stratification method. However, the OAG argues[69] that the use of plant stratification method in the past rate cases has aligned costs with the principle of cost-causation, but in the case of Nobles and Grand Meadow, it has slightly over-classified the capacity portion of these facilities.

Unlike traditional generation units, these facilities, the OAG maintains, were not added to minimize the total costs of its system over time — an assumption of the plant stratification method. Rather, these wind resources were added to comply with Minnesota's Renewable Energy Standard (RES) [70] which requires Xcel to generate or procure at least 18-percent percent of its total retail electric sales to retail customers from renewable technologies. Therefore, since they were explicitly added to comply with the RES, Xcel's investment in the Nobles and Grand Meadow wind resources corresponds directly with the energy consumption of its customers, and is not impacted by the company's peak demand requirement. Classifying Xcel's Nobles and Grand Meadow wind generation as energy recognizes the different purpose of these facilities and better aligns with cost-causation principles than continuing to use the same plant stratification method applied to other traditional generating resources.

MCC

MCC notes that Nobles and Grand Meadow were not built to reliably serve energy or capacity needs and that they were built to comply with the RES. Accordingly, MCC argues that the equivalent peaker method of classification is not applicable and a separate classification and allocation method for these two facilities is appropriate.[71]

MCC notes that because the "renewable-based PPAs are energy only," the entire cost recovery is through fuel costs." MCC adds that the PPA resource also contains some accredited capacity but "there is no allocation of the accredited capacity related costs in a demand basis."[72] Based on this, MCC argues that wind generation (and other renewable generation) acquired through PPAs should have the accredited portion classified as capacity-related, or alternatively, Grand Meadows and Nobles related costs could be allocated on the basis of the summer peak demand allocator.[73]

MCC offered for consideration another alternative to the classification of Grand Meadow and Nobles wind facilities. It recommends that the classification and allocation be based on the

[69] OAG Post-Hearing Brief at 56.
[70] See OAG Post Hearing Brief at 56. Minn. Stat. § 216B.1691, Subd. 2a(b).
[71] Maini Direct at 22.
[72] Maini Direct at 22-23.
[73] Maini Direct at 23.

percent of base revenues[74] (the "Percent of Base Revenue" method). Such an approach, MCC argues, would recognize that resources built for policy reasons are neither built to reliably serve capacity nor energy needs. MCC notes that 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. MCC claims that this method is also used currently in Xcel's RER Rider (Staff is certain MCC meant RES rider, Docket E002/M-10-1066), and was implemented after rigorous debate and analysis at the Commission.

Comparison of Recommended Treatment of Nobles and Grand Meadow Wind Facilities

Xcel provided the following comparison of the allocation of Nobles- and Grand Meadow-related revenue requirement by the parties:[75]

Table 7

	Total	Res.	Non-Demand	Demand	Street Ltg.
OAG (100% Energy)	100.00%	28.91%	3.29%	67.37%	0.43%
Department (Plant Stratification)	100.00%	29.16%	3.31%	67.12%	0.41%
Company (100% Capacity)	100.00%	34.52%	3.68%	61.80%	0.00%
MCC (Base Revenues)	100.00%	39.22%	4.03%	55.57%	1.18%

ALJ Analysis and Recommendation (excluding footnotes)

The ALJ discusses this issue in ¶¶ 691-709, pp. 158-162.

The ALJ concluded:

> 706. The Administrative Law Judge concludes that the Company has not demonstrated that it is reasonable to classify the Grand Meadow and Nobles generation facilities as 100 percent capacity-related. As the Commission noted in its 10-971 ORDER, wind facilities generally replace other energy resources, and "contribute very little to capacity" because they are only available when the wind blows. The Company has failed to provide any evidence that Nobles and Grand Meadow have any different operational characteristics than other wind facilities that would justify classifying them as 100 percent capacity-related. The fact that these facilities were built to satisfy a legislative renewable energy policy does not change their operational characteristics, and therefore does not provide a rational basis for classifying these facilities as 100 percent capacity-related.

[74] In E-002/M-10-1066, the Commission's October 17, 2011 Order, p. 3, described the working of the allocation according to base revenue thus: "Under this method, the apportionment of revenue requirement among customer classes is determined by dividing the base revenues for each class (excluding fuel costs and other riders) by the total base revenues to develop a class allocator. The allocator percentages are then used to assign the share of total retail costs to be recovered from each class."

[75] Peppin Rebuttal at 22.

707. Nor is the classification of the Nobles and Grand Meadow costs as 100 percent capacity-related justified by the Company's recovery of the costs of wind energy PPAs through its fuel charge. The CCOSS is not the proper forum for mitigating the effects of the fuel clause as a cost recovery mechanism for purchased power.

708. Just as classifying wind generation as 100 percent capacity-related is not reasonable, neither is the alternative of classifying wind generation as 100 percent energy-related as suggested by the OAG. Such a classification is inconsistent with the Commission's determination in the 10-971 rate case that wind generation provides some limited capacity value.

709. The Commission has repeatedly confirmed the Company's use of the Plant Stratification method for the proper classification and allocation of the Company's production plant, including costs of Company-owned wind generation. The application of the Plant Stratification method to wind generation continues to be the most reasonable alternative shown in the record. Accordingly, the Administrative Law Judge recommends that the Commission require the Company to modify its 2014 and 2015 Step CCOSSs to classify the costs of the Grand Meadow and Nobles wind farms on the same basis as its other fixed production plant costs using the Plant Stratification method.

Xcel's Exception to the ALJ's Finding and Recommendation

Xcel requests that the ALJ Report Findings 706 and 709 be amended as follows:[76]

706. ~~The Administrative Law Judge concludes that the~~ The Company has ~~not~~ demonstrated that it is reasonable to classify the Grand Meadow and Nobles generation facilities differently than other production plant in recognition of the ~~as 100 percent capacity-related. As the Commission noted in its 10-971 ORDER, wind facilities generally replace other energy resources, and "contribute very little to capacity" because they are only available when the wind blows.[1078] The Company has failed to provide any evidence that Nobles and Grand Meadow have any different operational characteristics than other wind facilities that would justify classifying them as 100 percent capacity-related. The~~ fact that these facilities were built to satisfy a legislative renewable energy policy. ~~does not change their operational characteristics, and therefore does not provide a rational basis for classifying these facilities as 100 percent capacity-related.[1079]~~

709. Pleasant Valley and Borders were added to minimize system costs on the same basis as other production plant. It is therefore reasonable to classify these projects using the Plant Stratification method. As for Nobles and Grand Meadow, there are four alternatives before the Commission:

Table
Percentage of Nobles and Grand Meadow Costs Allocated to Classes

[76] Xcel also requests (Xcel Exceptions, p. 28) amendment to ALJ's Report, ¶ 698, page 159, but not elaborated here because it does not pertain to the ALJ's finding/recommendation.

	Residential	C&I Non-Demand	C&I Demand	Lighting
OAG (100% Energy)	28.91%	3.29%	67.37%	0.43%
Department (Plant Stratification)	29.16%	3.31%	67.12%	0.41%
Company (100% Capacity)	34.52%	3.68%	61.80%	0.00%
MCC (Base Revenues)	39.22%	4.03%	55.57%	1.18%

The cost allocation under the Company's proposal reasonably reflects the policy nature of the Nobles and Grand Meadow projects and is reasonable overall; it should be adopted in this case for these specific policy-related resources. ~~The Commission has repeatedly confirmed the Company's use of the Plant Stratification method for the proper classification and allocation of the Company's production plant, including costs of Company-owned wind generation. The application of the Plant Stratification method to wind generation continues to be the most reasonable alternative shown in the record. Accordingly, the Administrative Law Judge recommends that the Commission require the Company to modify its 2014 and 2015 Step CCOSSs to classify the costs of the Grand Meadow and Nobles wind farms on the same basis as its other fixed production plant costs using the Plant Stratification method.~~

Xcel also requests that the ALJ Report's Finding 707 be deleted in its entirety.

MCC's Exception to the ALJ's Finding and Recommendation

MCC asks for the adoption of the following modified findings and conclusions:

> 706. The Administrative Law Judge concludes that the Company has not demonstrated that it is reasonable to classify the Grand Meadow and Nobles generation facilities as 100 percent capacity-related. As the Commission noted in its 10-971 ORDER, wind facilities generally replace other energy resources, and "contribute very little to capacity" because they are only available when the wind blows, at the same time the investments were not made to produce least-cost energy. ~~The Company has failed to provide any evidence that Nobles and Grand Meadow have any different operational characteristics than other wind facilities that would justify classifying them as 100 percent capacity related~~. The fact that these facilities were built to satisfy a legislative renewable energy policy does not change their operational characteristics, and therefore does not provide a rational basis for classifying these facilities as 100 percent capacity-related. But the fact that these facilities were built to satisfy a legislative renewable energy policy AND that they were not least cost, supports an alternative allocation that impacts all ratepayers in a manner that is consistent with respect to overall base rates. Percent of Base Revenue method is appropriate for these assets not purchased in the regular resource need based manner.

> 709. The Commission has repeatedly confirmed the Company's use of the Plant Stratification method for the proper classification and allocation of the Company's production plant, including costs of Company-owned wind generation. The application of the Plant Stratification method to wind generation continues to be the most reasonable alternative shown in the record if the resources were acquired as part of least cost resource

> planning. Grand Meadow and Nobles were not purchased as a least cost resource, so should be allocated with the percent of base revenue method. Accordingly, the Administrative Law Judge recommends that the Commission require the Company to modify its 2014 and 2015 Step CCOSSs to classify the costs of the Grand Meadow and Nobles wind farms on the same basis as it does in the RES rider, with the Percent of Base Revenue method ~~its other fixed production plant costs using the Plant Stratification method~~.

OAG's Exception to the ALJ's Finding and Recommendation

The OAG complains that despite the fact that Xcel's Nobles and Grand Meadow facilities were acquired for a different purpose than its Pleasant Valley and Border Winds facilities, the ALJ determined that they should be classified based on the same methodology.

The OAG seeks the following amendments:

> 706. The Administrative Law Judge concludes that the Company has not demonstrated that it is reasonable to classify the Grand Meadow and Nobles generation facilities as 100 percent capacity-related. As the Commission noted in its 10-971 ORDER, wind facilities generally replace other energy resources, and "contribute very little to capacity" because they are only available when the wind blows. The Company has failed to provide any evidence that Nobles and Grand Meadow have any different operational characteristics than other wind facilities that would justify classifying them as 100 percent capacity-related. ~~The fact that these facilities were built to satisfy a legislative renewable energy policy does not change their operational characteristics, and therefore does not provide a rational basis for classifying these facilities as 100 percent capacity-related.~~

> 708. ~~Just as classifying wind generation as 100 percent capacity-related is not reasonable, neither is the alternative of classifying wind generation as 100 percent energy-related as suggested by the OAG. Such a classification is inconsistent with the Commission's determination in the 10-971 rate case that wind generation provides some limited capacity value.~~
> The OAG has demonstrated that it is most reasonable to classify the company's Nobles and Grand Meadow facilities as energy. These facilities were built to comply with the company's RES mandate, which is measured by the company's energy sales. Moreover, the NARUC Electric Manual suggests that capital costs incurred to reduce fuel consumption should be classified as energy.

> 709. The Commission has ~~repeatedly confirmed~~ previously ordered the Company's use of the Plant Stratification method ~~for the proper classification and allocation of~~ to classify and allocate the Company's production plant, including costs of Company-owned wind generation. The application of the Plant Stratification method to wind generation ~~continues to be~~ is not the most reasonable alternative shown in ~~the~~ this record. Accordingly, ~~the Administrative Law Judge recommends that~~ the Commission requires the Company to modify its 2014 and 2015 Step CCOSSs to classify the costs of the Grand Meadow and Nobles wind farms as energy ~~on the same basis as its other fixed production plant costs using the Plant Stratification method~~.

Options

C. ii. 1 Adopt the ALJ's findings and recommendation.

C. ii. 2 Adopt Xcel's exceptions and modifications.

C. ii. 3 Adopt the MCC's exceptions and recommendation.

C. ii. 4 Adopt the OAG's expeditions and recommendation.

(Note: These decision alternatives correspond to alternatives IV, B, 3 (a through d) on p. 28 of the deliberation outline.)

C. iii. Updating of Fixed Production Plant Cost Data

Introduction

In the rebuttal testimony of Xcel's witness Peppin, it was stated that in the original CCOSS, the replacement cost and summer capacity rating data from the Nobles and Grand Meadow projects were used as a proxy in the Plant Stratification analysis for Pleasant Valley and Borders. As those data have since become available, Peppin's rebuttal testimony stated that the "rebuttal CCOSS" had incorporated the new data into the Rebuttal 2015 CCOSS.[77]

As the ALJ observes in ¶ 711, the Department questioned the propriety of presenting updated data in Rebuttal Testimony. The Department noted that the Company limited its update of its initially filed 2012 cost data in the 2015 Step CCOSS to the Pleasant Valley and Border Winds projects, even though 2013 cost data were available for all production plant costs. If the Commission finds the updated cost data acceptable, the Department stated, the Company should be required to use 2013 data for all fixed production plant costs as well as plant-specific data for Pleasant Valley and Border Winds in the application of its Plant Stratification methodology.

ALJ's Finding and Recommendation

> 712. Newly received cost information, if presented in a timely and consistent fashion, can help provide the most accurate cost causation information for participants and decision-makers. In this case, the Department has not indicated that the information was filed too late for it and other parties to analyze in the rate case. Therefore, the Administrative Law Judge concludes it is reasonable to require the Company to update its CCOSS results using 2013 cost data for Pleasant Valley and Border Winds as well as for all other production plant costs in its Plant Stratification analysis.

[77] Peppin Rebuttal at 3.

Parties' Exceptions to the ALJ's Finding and Recommendation

No party took exception to the ALJ's recommendation.

Options

C. iii.1 Adopt the ALJ's finding and recommendation.

C. iii.2 Other action by the Commission.

(Note: These decision alternatives correspond to alternatives IV, B, 4 (a and b) on p. 28 of the deliberation outline.)

C. iv. Use of the D10S Capacity Allocator for Allocating the Capacity-Related Portion of Fixed Production Plant[78]

Introduction

As noted before, fixed generation costs consist of capacity- as well as energy-related costs and they are classified through the plant stratification process.

After the fixed generation costs have been classified, they are then allocated to the customer classes based upon each class' demand that is coincident with the Xcel system peak

In Xcel's CCOSS, the capacity-related portion is allocated to the various classes by determining <u>each class' load that is coincident with the Xcel system peak</u>, as measured by the test year class hourly load shapes.[79] This allocator is called D10S. It is the class contribution to the system summer peak that drives the capacity-related portion of fixed generation costs.[80]

Xcel notes that it meets this peak demand through a combination of Company-owned generation, purchases, and load management programs, and adds reserves above that needed to meet peak demand to ensure system reliability.

Xcel points out that Midcontinent Independent System Operator, Inc.'s (MISO) new resource adequacy rules, effective June 1, 2013 require that the planning reserve margin requirements must be based on a utility's peak that is coincident with MISO's peak, which is in the summer.[81] Xcel also notes that the summer-only allocator is consistent with the cost-causation principle.

The energy-related portion of fixed generation costs is allocated to customer classes using Xcel's E8760 energy allocator. No controversy or dispute surrounds this aspect.

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[78] Includes generation and transmission costs. Peppin Direct, Exhibit MAP-1, Schedule 2, Appendix 2, page 2 of 4.
[79] ALJ Report, ¶ 713.
[80] Peppin Direct at 14.
[81] Peppin Direct at 14-15.

Parties' Position

OAG

The OAG objects to Xcel's use of the D10S allocator.

The OAG recommends calculating the D10S using each class's demand that is coincident with MISO's peak, not the Company's peak.[82] The OAG believes that D10S should be calculated using the load that is coincident with MISO's peak because it is consistent with MISO's resource adequacy rules and better reflects cost causation.[83]

The OAG opposes the summer-peak D10S not so much because of its inappropriateness as its alleged improper calculation. The OAG maintains that Xcel is not calculating the D10S allocator to most effectively encompass cost causation.[84] The OAG notes that Xcel's use of the D10S allocator is contradictory because costs are caused by Xcel's coincident peak with MISO, but Xcel uses its own system peak to calculate the D10S. The OAG also points out that Xcel has cited MISO resource adequacy rules that require the Company to meet the demand coincident with MISO, not Xcel's own peak.[85] The OAG argues that because, in recent years, Xcel's system peak is higher than its coincident peak with MISO and that the "the current D10S demand allocator is calculated in a way that likely results in a higher allocation of costs to the Residential class than they cause."[86] The OAG also notes that the MISO peak occurs earlier in the day than does the NSP peak and residential customers would represent a lower proportion of the MISO peak.[87]

MCC

MCC notes that if Xcel's equivalent peaker method is retained, then Xcel should continue to use the D10S allocator (based on summer peak) for allocating fixed production plant classified as demand-related.[88]

MCC supports Xcel's use of the D10S allocator based on the summer peak on the ground that Xcel adds resources to its system in order to meet peak demand which occurs in the summer.[89] MCC adds that if a customer class contributes 20% to the system peak demands, it represents 20% of the need for the generating capacity and therefore should be assigned or allocated 20% of the costs.

[82] ALJ Report, ¶ 715.
[83] Nelson, Surrebuttal at 11.
[84] Nelson Direct at 4.
[85] Nelson Direct at 11.
[86] Nelson Direct at 11-12.
[87] Nelson Surrebuttal at 12-13.
[88] Maini Direct at 20.
[89] Maini Direct at 21.

XLI

XLI supports the use of D10S allocator noting that Xcel is a predominantly summer-peaking utility and that electric demands in the other months are not relevant in determining the amount of capacity needed for Xcel to provide reliable service.[90]

Xcel

Xcel agrees that the OAG's method of calculating the D10S allocator would be consistent with MISO's resource adequacy rules and would reflect cost causation, but Xcel notes that it does not possess the data to perform the calculations suggested by the OAG. Xcel adds that MISO does not produce a forecast of its hourly loads for the test year, or alternatively, a projection of its peak hour and, therefore, it is not possible to calculate a D10S allocator using class peaks that are coincident with MISO's peak.[91]

Xcel also noted that there is no way of knowing how each class' share of the MISO peak differs from each class' share of the NSP system peak. Xcel notes that in order to calculate the D10S allocator based on the MISO peak, MISO would need to publish an hourly forecast that is compatible with the test year. MISO does not publish such a forecast, making the OAG's recommendation infeasible.[92]

Note: The OAG responded that if the data are not currently available, the Company should collect the data required for the calculation.[93]

ALJ's Conclusion

> 717. The OAG recommended that the Commission require the Company to collect the data necessary to perform the calculation. The OAG's witness Ron Nelson acknowledged, however, that he is "unaware of the data that is currently available or could be acquired in the future" to support the calculation. Therefore, while the OAG has raised a noteworthy issue, the Administrative Law Judge concludes that the OAG has not developed a sufficient record in this proceeding to support the viability of its recommendation.

OAG's Exception to the ALJ's Conclusion[94]

The OAG noted that neither the OAG nor the ALJ could recommend a specific adjustment to the CCOSS because of Xcel's claim that it could not calculate a capacity allocator using MISO's system peak. However, the ALJ's revenue requirement recommendation should still have considered this imprecision in the CCOSS, but it did not.

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[90] Pollock Direct at 57.
[91] Peppin Rebuttal at 38.
[92] Xcel Reply Brief at 142.
[93] Nelson, Surrebuttal at 13.
[94] OAG Exceptions, at 26-27.

Options

C. iv. 1 Adopt the ALJ's conclusion in finding 717.

C. iv. 2. Adopt the OAG's recommendation and incorporate language into the Order to suggest that neither the OAG nor the ALJ could recommend a specific adjustment to the CCOSS because of Xcel's claim that it could not calculate a capacity allocator using MISO's system peak. Further, acknowledge in the Order that the calculation of the D10S allocator based on Xcel's own system peak is a deficiency and encourage Xcel to work with MISO and other parties to find a way to recalculate D10S on the basis of MISO peak.

(Note: These decision alternatives correspond to alternatives IV, B, 5 (a and b) on p. 29 of the deliberation outline.)

C. v. Allocation of Other Production Operation and Maintenance (O&M) Costs

Introduction

The Other Production O&M (Operation and Maintenance) expense category includes labor, materials, supplies and the supervision and engineering expenses associated with operating and maintaining all of the Company's power plants <u>except</u> fuel and purchased power expenses.[95]

In the 2013 rate case, Xcel classified and allocated Other Production O&M costs based on the relative capacity and energy splits of overall plant investment -- what it calls "overall investment method." Under this methodology, <u>in the previous rate case</u>, <u>75 percent of the cost was allocated based on energy, while the remaining 25 percent of all Other Production O&M cost was considered capacity-related.</u>

The Commission's September 3, 2013 Order in the previous rate case, 12-961, required[96] that

> Xcel shall refine its Class Cost of Service Study cost allocation method by identifying any and all Other Production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, while allocating the remainder of Other Production O&M costs on the basis of the Production Plant.

Xcel termed this allocation method ordered by the Commission for use in this instant rate case the "location" method. [97, 98]

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[95] Peppin Rebuttal at 23.
[96] Ordering paragraph 49, September 3, 2013 Order, E-002/GR-12-961, p. 53.
[97] Peppin Direct at 22.
[98] OAG Post-Hearing Brief at 59: "The location method classifies Other Production O&M costs using the same classifications as the plant in which the costs were incurred. For example, under the location method, the Other

Xcel indicated that there is another method of allocating the other production O&M costs called the "predominant nature method."[99] Xcel notes that the predominant nature method is similar to the initial analysis required by the Commission in the previous rate case, but goes beyond those costs that strictly vary based on the amount of energy produced.[100]

Xcel indicates that it would be appropriate to evaluate the results under the predominant nature method and the location method required by the Commission in the previous rate case.[101] Accordingly, Xcel notes that it analyzed 117 cost items that make up the Other Production O&M cost category and placed them into the following 15 categories:

Other Production O&M Cost Categories:

1. Employee Labor
2. Contract and Consulting Labor
3. Employee Expenses
4. Hardware Software and Networking Expense
5. Chemicals
6. Materials
7. License Fees, Permits, Regulatory Expense and Association Dues
8. Facilities Maintenance (Janitorial, Snow Removal, Sewer Maintenance, Etc.)
9. Transportation Fleet Cost
10. Nuclear Outage Amortization Costs
11. Office Supplies and Equipment
12. Electric Use Costs
13. Gas Use Costs
14. Water Use Costs
15. Steam, Nuclear, Hydro Generation Rents

Xcel then proceeded to analyze whether each category was predominantly capacity-related or predominantly energy-related. In so doing, <u>Xcel assumed all labor costs to be predominantly fixed, while material costs were assumed to be predominantly variable</u>. Xcel's analysis showed: 1) chemicals and water usage vary directly with the amount of energy produced; and 2) other types of Other Production O&M costs could be identified as being primarily fixed (capacity-related) or variable (energy-related) in nature.[102]

Production O&M costs incurred at a nuclear facility will be classified between energy and capacity functions according to the applicable classifications for a nuclear facility."

[99] "The predominant nature method classifies entire cost categories based on whether the cost category is considered 'predominantly' capacity or energy-related. For instance, since labor costs do not vary significantly based on the amount of energy produced, the predominant nature method considers them to be predominantly capacity related, and allocates labor costs entirely as capacity. On the other hand, since material costs are considered variable, all material costs are classified as energy." See the OAG Post-Hearing Brief at 59.

[100] Peppin Direct at 22.

[101] Peppin Direct at 22.

[102] Xcel Exceptions, at 23.

Based on the predominant nature method, approximately 78.4 percent of Other Production O&M costs are classified as capacity-related and 21.6 percent are classified as energy-related.

According to the location method, 65% of the other O&M costs are energy-related, while the remaining 35% are related to capacity.[103]

The following table captures the percentage split between the capacity-related and energy-related costs according to the two methods as well as the split that was last seen in the previous rate case:

Classification Methodology	Capacity-Related	Energy-Related
Location Method	35.0%	65.0%
Predominant Nature Method	78.4%	21.6%

Xcel did not use the Location method ordered by the Commission in its proposed CCOSS, but rather used the Predominant Nature method.

Xcel argues that the predominant nature methodology is more consistent with the intent expressed during the 2013 rate case and that Xcel has taken a more expansive view of energy-related Other Production O&M costs.

Parties' Position

Department

The Department argues that the Location method is the most reasonable basis for allocating other production O&M costs. The Department also argues that Xcel's proposed classification and allocation of Other Production O&M costs is a substantial change from the classification and allocation methods that the Commission previously approved and from the current Commission-required classification and allocation method.[104] The Department found that Xcel essentially classified fixed expenses as capacity-related and variable expenses as energy-related.[105]

The Department notes that the overall investment method used by Xcel in the 12-961 rate case and the refinement of that method, now called the "location method," are reasonable because they reflect allocation of generation plants at which these costs are incurred. The Department also indicates that Xcel had argued against its current proposal in its last two rate cases disputing the assertion that it is reasonable to assign "fixed" costs entirely to demand (or capacity).

The use of the location method, the Department points out, results in a decrease of about $12.5 million in the Residential class's contribution to Xcel's revenue requirements with a

[103] Peppin Direct, Table 7, at 21.
[104] The Department Reply Brief at 58.
[105] The Department Post-Hearing Brief at 273.

corresponding increase of about $12.4 million in the Commercial and Industrial Demand class contribution to Xcel's revenue requirements for the test year 2014.[106]

OAG

The OAG recommends that the other production O&M expenses continue to be classified based on the location method.[107]

The OAG argues that the problem with the predominant nature method is that it fails to distinguish between the costs associated with operating different plants that contribute differently to a utility's system. The predominant nature method would, for example, classify all labor costs incurred at a nuclear facility as capacity costs. But since nuclear facilities contribute largely to energy production, classifying labor costs from these plants as capacity leads to warped and absurd results.[108] Therefore, the predominant nature method is a less precise method in determining cost causation than the location method.

The OAG adds that using the predominant nature method in this case would result in a dramatic shift in the classification of these costs, with only a 21.6 percent weighting as energy and 78.4% as capacity — increasing the costs allocated to the Residential class in Xcel's CCOSS by $12.5 million.[109]

MCC[110]

MCC supports Xcel's use of the predominant nature method on four grounds: (1) Xcel was ordered to analyze the other production O& M costs by the Commission in the previous rate case; (2) Xcel did a detailed analysis of the nature of the expense; (3) costs that vary with energy usage should be classified and allocated on the basis of energy and those that are fixed should be classified and allocated on the basis of demand; and (4) the NARUC manual classifies the predominant nature method as commonly used, while the location method is not standard practice.

XLI[111]

XLI asks the Commission to reject the Department's recommendation because, first, it is not consistent with accepted practice. Second, it is contrary to the spirit of the Commission's order in the last rate case (which authorized NSP to refine the overall investment or "location" methodology authorized and used in prior rate cases). XLI believes that Xcel's proposed allocation of these expenses is clearly more refined and reflects standard practice as defined in the NARUC Electric Utility Cost Allocation Manual.

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106 The Department Post-Hearing Brief at 274.
107 OAG Post Hearing Brief at 2 and 79.
108 OAG Post-Hearing Brief at 59.
109 OAG Post-Hearing Brief at 60.
110 MCC Post-Hearing Brief, pp. 17-18.
111 Pollock Surrebuttal at 5.

ALJ's Finding and Recommendation

Paragraphs 734 through 736 contain the ALJ's findings and recommendation:

> 734. The propriety of the Overall Investment method for classifying Other Production O&M Costs has been confirmed in past Company testimony and in past Commission orders. In the last rate case, the Commission required a further refinement of the method through the application of the energy allocator to costs that vary directly with the amount of energy produced and allocation of the remainder of costs on the basis of Plant Production. As noted above, this approach is known as the Location method. In contrast, the Company's application of the Predominant Nature method goes beyond the refinement ordered by the Commission in the last rate case by assigning all remaining costs based on their "predominant nature."
>
> 735. The Company has not shown that its grouping and analysis of these Other Production O&M Costs based on their predominant nature moves the marker closer to cost causation. The Predominant Nature method displays the same oversimplified fixed/variable analysis that the Commission has previously found lacking. The Location method, required by the Commission in the 12-961 ORDER, is the most reasonable method of classifying Other Production O&M Costs in the record.
>
> 736. For these reasons, the Administrative Law Judge recommends that the Commission require the Company to modify its 2014 and 2015 CCOSSs to use the Location method rather than the Predominant Nature method.

Xcel's Exception to the ALJ's Recommendation

Xcel asks that the Commission find the predominant nature method to be the more reasonable method of allocating Other Production O&M costs in this case. Xcel argues that it alone provided the detailed analysis of Other Production O&M in the record, while proponents of the location method rely only on past practice. The analysis provided by the Company was different from analyses presented in past rate cases and does, in fact, move the marker closer to cost causation. The Department has presented no explanation why it is reasonable to classify costs that vary directly with the amount of energy produced (i.e. chemicals and water use) as energy-related but unreasonable to classify costs that are clearly unrelated to the amount of energy produced (i.e. license fees and computer costs) as capacity-related.

Xcel recommends the following amendment to the ALJ's findings for Commission approval:

1) Delete ALJ Report Findings ¶ 735 and ¶ 736 in their entirety;

2) Delete ¶ 734 in its entirety and <u>**replace** it with the following alternative language</u>:

> 734. The Company's use of the predominant nature method in its proposed CCOSSs is reasonable. The predominant nature method is a refinement of past practice

supported by a new analysis. The Company's examination of each of the 117 cost items that make up Other Production O&M avoids the need to rely on proxies in the classification process. The method is also considered "common" practice, while the locational method is "not standard." The Company's proposal is therefore reasonable and should be adopted.

3) Correct the ALJ Report Finding ¶ 725 as follows:[112]

725. The Company determined that application of the Location method to these costs results in ~~65~~ 35 percent of Other Production O&M costs being classified as capacity-related and ~~35~~ 65 percent energy-related. Application of the Predominant Nature method, on the other hand, resulted in 78.4 percent of these costs being classified as capacity-related and 21.6 percent as energy related.

MCC's Exception to the ALJ's Recommendation

MCC seeks the Commission to modify the ALJ's findings and conclusion thus:

733. MCC and XLI supported the Company's use of the Predominant Nature Method. MCC identified consistency in using Predominant Nature method with NARUC, FERC allocation and in how Xcel allocates the cost for jurisdictional purposes.

735. The Company has ~~not~~ shown that its grouping and analysis of these Other Production O&M Costs based on their predominant nature moves the marker closer to cost causation. ~~The Predominant Nature method displays the same oversimplified fixed/variable analysis that the Commission has previously found lacking. The Location method, required by the Commission in the 12-961 ORDER, is the most reasonable method of classifying Other Production O&M Costs in the record.~~

736. For these reasons, the ~~Administrative Law Judge recommends that the~~ Commission ~~require the Company to modify its 2014 and 2015 CCOSSs to use the Location method rather than~~ should approve use of the Predominant Nature method.

Options

C. v. 1. **a)** Adopt the ALJ's finding and recommendation and require the Company to modify its 2014 and 2015 CCOSSs to use the Location method rather than the Predominant Nature method.

b) In addition, Staff recommends that the Commission retain the present requirement established in docket, E-002/GR-12-961, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, Findings of Fact, Conclusions, and Order, September 3, 2013, ¶ 49:

[112] This is a clerical correction, and consistent with the material at p. 34 of the briefing papers.

> In the initial filing of its next rate case, Xcel shall refine its Class Cost of Service Study cost allocation method by identifying any and all Other Production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, while allocating the remainder of Other Production O&M costs on the basis of the Production Plant.

c) Staff also recommends that the Commission incorporate the following language from the Findings of Fact, Conclusions, and Order in the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota, G-008/GR-13-316, June 9, 2014, ¶ 23:

> In its next rate case the Company's class cost of service study shall include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered by the Company, whether those methods are based on the Manual of the National Association of Regulatory Utility Commissioners or the Company's specific system requirements, its experience, and its engineering and operating characteristics. The Company shall also explain its reasoning in cases in which it did not consider alternative methods of allocation or classification.

C. v. 2. Adopt Xcel's position as noted in its Exceptions.

C. v. 3. Adopt MCC's position as noted in its Exceptions.

(Note: These decision alternatives correspond to alternatives IV, B, 6 (a through e) on pp. 29-30 of the deliberation outline.)

C. vi. The Use of the Minimum Distribution System

Introduction

An electric utility's costs are functionalized according to the three major functions: production, transmission, distribution.

Xcel's distribution costs do not include the energy classification. Metering costs and customer costs are classified by Xcel exclusively as customer-related costs. The cost of primary lines, secondary lines, secondary transformers and service drops are classified as both demand- and customer-related costs in the distribution function.

The three cost functions, excluding the customer service function, and their related cost classifications are provided below:

Cost Function	Cost Classification
Production	Demand Energy
Transmission	Demand Energy
Distribution[113]	Demand Customer

Xcel's distribution system consists of distribution substations, primary transformers, primary lines, secondary lines, secondary transformers, and service drops. Xcel has classified distribution substations and primary transformers as exclusively demand-related. The remaining sub-functions, Xcel claims, are driven by both the numbers of customers on the distribution system and the capacity requirements they place on the system. "The analysis used to separate these costs into demand and customer components is called the Minimum Distribution System (MDS) method."[114]

The MDS method involves comparing the cost of the minimum size of each type of facility used, with the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between actual installed cost and the minimum sized cost

The following table shows the percent of each cost element that was classified as customer-related based on the most recent Minimum Distribution System study:[115]

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[113] The NARUC Electric Utility Cost Allocation Manual (1992) allows for some energy-component of cost in the distribution function but maintains that electric distribution is affected "primarily by demand and by the number of customers." See p. 21 of the Manual.
[114] Peppin Direct, Exhibit___ (MAP-1), Schedule 2, Page 5 of 11.
[115] Peppin Direct, Exhibit___ (MAP-1), Schedule 2, Page 6 of 11.

Equipment Type	% Classified as "Customer" Related
Overhead Lines Primary	38.8%
Primary Transformers	0%
Overhead Lines Secondary	50.2%
Underground Lines Primary	83.0%
Underground Lines Secondary	52.5%
Line Transformers Secondary	45.6%
Services	72.7%

Parties' Position

OAG

The OAG maintains that the theory of the minimum distribution system involves determining the smallest (or minimum-sized) distribution equipment installed by a utility and constructing a hypothetical distribution system entirely from this minimum-sized equipment. The costs associated with this hypothetical minimum distribution system are classified as customer costs, while all costs of the utility's distribution system that exceed this hypothetical minimum system are denoted as demand costs.[116]

The OAG argues that there is an alternative method of estimating the customer-related costs called the "zero-intercept" or "minimum-intercept" method.[117] Both the MDS and the "zero-intercept" methods design a hypothetical minimum distribution system, but they are "conceptually different from one another and, even if performed correctly, will likely lead to different results."[118]

The OAG notes that while the MDS is simple to use,[119] it overestimates the customer cost "because incremental increases in equipment size or load capability are linked to demand rather than customer cost."[120] More explicitly, the OAG maintains that the "minimum system not only overestimates customer costs by including material costs, but also by using equipment that is not the smallest installed within the system and by constructing the minimum system based off the standard or maximum system requirements in some instances."[121]

The OAG argues that the minimum-sized method, as opposed to the zero-intercept method, "incorrectly classifies some costs of providing load to customers — and, therefore, recording demand costs as customer costs."[122]

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[116] OAG Post-Hearing Brief at 47.
[117] This method involves a statistical method call regression analysis where a dependent variable is explained by a set of independent variables. The procedure requires an abundance of data for its success.
[118] OAG Post-Hearing Brief at 47.
[119] In contrast, Xcel maintains that "[a] zero-intercept study requires much more data than does the MDS method, making it a much more time consuming and expensive process." Pippin Rebuttal at 34.
[120] Nelson Direct at 16.
[121] Hearing Transcript, Vol. 3, 228: 8-14.
[122] OAG, Post-Hearing Brief at. 48.

The OAG asks that the Commission require Xcel to conduct "the more precise" zero-intercept analysis in future rate cases, and also require Xcel to provide parties with data sufficient to verify and reproduce its minimum system study.

As to the present rate case, the OAG recommends that Xcel's CCOSS be adjusted to classify and "allocate 10% more capacity costs and 10% less customer costs than recommended by Xcel."[123] This adjustment is a countervailing offset to the inherent over-classification of customer costs in the minimum distribution system. The OAG believes this adjustment to be reasonable, given that subtracting the material costs provided by Xcel from the average installation costs could be considered as a proxy for the zero-intercept method and would result in a larger downward adjustment. [124]

Xcel

Xcel notes that the OAG's assertion that MDS overstates customer-related costs has not been borne out by an actual zero-intercept study.[125]

Xcel argues that the OAG's proposed 10-percent adjustment is based on the cost of just one item, but ignores the cost of other items that are understated in Xcel's cost study.

In any event, Xcel stated that it was willing to reexamine the assumptions supporting its minimum distribution system study and the installed distribution costs in its next rate case, but that it did not possess the data to perform the zero-intercept analysis.

Xcel noted that, subject to the availability of data, it did not object to following the OAG's recommendation to file a zero-intercept analysis in its next rate case. But, Xcel cautioned that the differences between the two models may well be minimal.

Other Parties' Comments

No other party filed comments regarding this matter.

ALJ's Conclusion

> 744. The Administrative Law Judge concludes that the OAG has raised valid concerns regarding the value of the data the Company has used to support its minimum system study. The data presented were last gathered nearly a quarter of a century ago, with no attempt to provide fact-specific updates. Although the analysis under the Zero-Intercept method may be more rigorous than under the Minimum Size method, the NARUC Manual has found that it is more accurate. For these reasons, the Company should be required to file a zero-intercept analysis of distribution costs in its next rate case. In addition, because the Minimum Size method is a useful cross check of the

[123] OAG Post-Hearing Brief at 54.

[125] Xcel Post-Hearing Brief at 130.

Zero-Intercept method, the Company should also file an updated Minimum Distribution System study as a comparative analysis.

745. The gathering of more sophisticated and updated distribution cost information in the next rate case will be an ongoing improvement to the CCOSS. Requiring the updating of data and the filing of a zero-intercept analysis in the next rate case is a more reasonable approach to addressing the issues raised by the OAG than adjusting the Company's distribution costs by 10 percent in this case.

Xcel's Exception to the ALJ's Report

Xcel noted that the ALJ was correct to reject the 10-percent adjustment recommended by the OAG.

Xcel accepted the ALJ's recommendation that Xcel file an updated Minimum Distribution System study.

Xcel, however, asks that the filing of a zero-intercept study be conditioned based on its ability to gather the appropriate information.

Specifically, Xcel recommends the following amended ¶¶744 and 745:

744. ~~The Administrative Law Judge concludes that the~~ The OAG has raised ~~valid~~ concerns regarding the value of the data the Company has used to support its minimum system study. The OAG's analysis contains serious flaws and ultimately results in an arbitrary recommendation. The Company's classification of distribution related costs into customer-related and capacity-related components is reasonable for use in this case. ~~The data presented were last gathered nearly a quarter of a century ago, with no attempt to provide fact-specific updates.~~ Although the analysis under the Zero- Intercept method may be more rigorous than under the Minimum Size method, the NARUC Manual has found that it is more accurate, though the differences between the two methods is relatively small. Further, all Minnesota electric utilities either use the Minimum Size method in their respective cost studies or have been ordered to do so in subsequent rate cases, indicating the Commission does not view the zero-intercept method as being inherently superior to the minimum system method. For these reasons, it may be helpful for the Company ~~should be required~~ to file a zero-intercept analysis of distribution costs in its next rate case if it is able to collect the appropriate data. ~~In addition, because the Minimum Size method is a useful cross check of the Zero-Intercept method, the~~ The Company should also file an updated Minimum Distribution System study as a comparative analysis.

745. The gathering of more sophisticated and updated distribution cost information in the next rate case will be an ongoing improvement to the CCOSS. Requiring the updating of data and the filing of a zero-intercept analysis (if the Company is able to collect the appropriate data) in the next rate case is a more reasonable approach to addressing the issues raised by the OAG than adjusting the Company's distribution costs by 10 percent in this case.

Staff Comment and Recommendation

The NARUC 1992 Manual upon which the OAG depends for its espousal of the zero-intercept method, pronounces that the zero-intercept method is more accurate, "although differences may be small" in comparison with the MDS.[126] The technique of the zero-intercept method is very involved and requires considerable data. As described in the Manual:[127]

> The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component.

Despite the higher sophistication of the zero-intercept method, its efficacy may not be commensurate with the effort that it entails. The NARUC manual does not emphatically recommend this technique nor does it unequivocally endorse this method as unquestionably superior. In fact, its assessment is ambivalent -- contrast this assessment (page 90 of the Manual):

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

with the following assessment only a page later:

> In most instances, it [minimum-size method] is more accurate, although the differences may be relatively small.

The Manual notes that the zero-intercept method can produce "statistically unreliable results" as it relies upon extrapolating a statistically-estimated result to provide the customer-related costs. The Manual also faults the MDS: "The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs." While the MDS has a certain load-carrying capability, which can be viewed as a demand-related cost, in the zero-intercept method the customer cost of a particular piece of equipment has no demand cost in it whatsoever. Thus, the two methods, even at the conceptual level, are apparently diametrically opposed. "The exact difference between each method cannot be known in this case because Xcel claims to not have the necessary data to perform a zero-intercept analysis or necessary data for a properly conducted minimum-size method."[128]

Staff recommends that the Commission consider ordering Xcel to include the zero-intercept method in its next rate case filing if only to act as a useful cross-check on the MDS results. If the Commission decides to require Xcel to file a zero-intercept cost study, it would be consistent with the Commission's decision in the 2013 CenterPoint rate case (#13-316) and 2013 MERC rate case (#13-617). For example, in the MERC rate case (In the Matter of a Petition by Minnesota Energy

[126] NARUC Manual, at 92.
[127] ibid.
[128] OAG Post-Hearing Brief at 50.

Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota, G-011/GR-13-617, in its October 28, 2014 Order, on p. 61, the Commission stated that:

> 33. MERC shall submit two class cost of service studies in its next rate case, one based on the zero-intercept method and the other on the minimum-size method.

Staff is aware that Xcel may not have enough data to complete the zero-intercept analysis in a completely satisfactory manner. Even so, the importance of the matter requires that Xcel spare enough resources for a reasonably satisfactory completion of the analysis.

Staff also notes that there is additional discussion of the minimum-size versus zero-intercept method in the rate design volume of the briefing papers in the section on monthly customer charges.

Options

C. vi. 1. Adopt the ALJ's findings and recommendation and also incorporate the OAG's recommendation that Xcel provide parties with data sufficient to verify and reproduce its minimum system study.

C. vi. 2 Adopt Xcel's recommendation stated in Xcel's Exception to the ALJ's Report.

(Note: These decision alternatives correspond to alternatives IV, B, 7 (a and b) on p. 30 of the deliberation outline.)

C.vii. Allocation of Economic Development Discounts

Introduction

The economic development discounts are based on kWh consumed. Economic development discounts are treated as a reduction in revenues from the Commercial and Industrial (C&I) Demand class.

Xcel regards rate discounts as lost revenues because discounts reduce the revenue received from the class and thus has the effect of increasing the revenue requirement for the classes that receive the discounts.[129] Economic development discounts are a policy mechanism used to retain existing large customers and to attract new such customers.

The cost of these discounts is allocated to each customer class based on 2014 test year present revenues.[130]

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[129] Peppin Direct at 7-8.
[130] Peppin Direct at 7.

Xcel indicated[131] that in the 2013 rate case, the Commission decided that all rate classes should share in the cost of economic development discounts, but ordered Xcel to provide additional information in this present case regarding the appropriate cost allocation. In response, Xcel noted that it evaluated different allocation options: the method used in the 2013 rate case,[132] test year 2014 present revenues, and test year 2014 base revenues. The allocations factors involved in these three methods are presented below: [133]

Allocation Method	Residential	C&I Non-Demand	C&I Demand	Lighting
57% Capacity / 43% Energy[a]	32.3%	3.5%	64.0%	0.2%
100% Energy Sales (DOC & OAG)[b]	28.1%	3.1%	68.2%	0.6%
Present Revenues (Xcel)	35.9%	3.8%	59.4%	0.9%
Present Base Revenues (MCC)	39.2%	4.0%	55.6%	1.2%

[a] Peppin's Rebuttal marked this method as 61% Capacity/ 39% Energy.
[b] Peppin Rebuttal at p. 41.

Xcel allocated economic development discounts based on the percentage of each rate class' present revenue. Xcel justified this approach by arguing that it reasonably balances the interests of all classes in a way that is consistent with the overall goal of helping support economic development.[134]

Xcel noted, however, that it was "willing to work with parties throughout this proceeding to further evaluate the proper allocation of economic development discounts."[135]

Parties' Position

OAG

The OAG argues that because the discounts are based on Kwhs consumed, the Kwhs consumed are causing the costs.[136] Xcel's lost revenues for economic discounts provided to large energy customers should be allocated on an energy basis to reflect cost causation.[137] For this reason, the

[131] Xcel Post-Hearing Brief at 136.
[132] Xcel describes (Peppin Direct at 18:12-13) this method as "61 percent weighting of the capacity allocator and a 39 percent weighting of the energy allocator," but in the table on the same page, this method is represented as "57% Capacity / 43% Energy."
[133] Peppin Direct at 18.
[134] Peppin Direct at 19.
[135] Peppin Direct at 19.
[136] Staff Note: Generally, the discounts to large customers are based on the notion that the largest users make some contribution to the fixed/joint/common costs, and in the absence of which, the other customers (notably, residential) would have to bear the burden. This contribution is generally recognized to be a welcome addition to revenue (certainly better than no addition to revenue at all) benefiting all customers.
[137] OAG Post-Hearing Brief at 2.

OAG recommends that economic development discounts be classified as energy and allocated using a kWh allocator.

MCC

MCC recommends that the discount be allocated on the basis of test year 2014 present base revenues, and not present revenues.[138]

MCC argues that the "discount is associated with the contribution [to] fixed costs (i.e., base revenues) that the customer made prior to the discount."[139] MCC also argues that "retaining customers is not strictly for the purpose of retaining energy consumption, rather, it is for retaining base revenues." Because 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."[140]

Department

The Department recommends that Xcel allocate the economic development discounts on the basis of the present base revenue allocator. The Department offered the following reason for its opposition to Xcel's method of allocation economic development discounts:[141]

(1) such allocations would include embedded policy judgments as to rate design (from the Company's last rate case) rather than allocating costs based entirely on cost factors; and

(2) the magnitude of the economic development discounts is based on the Kwh's that the beneficiaries consume.[142]

XLI

XLI takes exception to the notion that economic development costs vary with the amount of energy consumed by customer classes and opposes allocating the economic development discounts on an energy basis. XLI goes on to state that "[e]conomic development is designed to retain revenues that NSP would otherwise lose if the customer ceased purchasing electricity from NSP. The revenues retained provide a contribution to NSP's fixed and variable costs. If a customer were to cease purchasing electricity from NSP, NSP would experience a revenue shortfall. This shortfall would have to be recovered from NSP's other customers in a subsequent

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[138] Staff Note: The distinction between base revenue and current revenue is not clear from the parties' submissions. What is given here is Staff's best understating of the matter. The base rates are established after a consideration of a utility's test year income and expenses. Income and expenses arising outside of the specified test year are not usually reflected in the rate calculation. See, Clark Direct at 5. Base revenues correspond to revenues from base rates. Costs incurred by a utility outside of the test year are recovered through approved "riders," or recovered in the next general rate case. "Present Revenues" include "base" revenues and revenues from "riders." Base revenues do not include revenues from riders.

[139] Maini Surrebuttal at 19.

[140] MCC Post-Hearing Brief at 22.

[141] Department Post-Hearing Brief at 275.

[142] The Department has adopted the OAG's reasoning here.

rate case. Thus, economic development costs are being incurred to mitigate future base rate revenue requirements. Successful implementation will mitigate future base rate increases."[143]

Xcel

Xcel contends[144] that the Department and the OAG recommend a narrowly-focused approach that considers how the economic development costs are incurred (i.e. on a per kWh basis) but ignores (or undermines) why they are incurred (i.e. to attract and retain large customers for the benefit of the system and customers). The overall allocation methodology should be consistent with the purpose of the discounts, as recommended by the Company, MCC and XLI.

Comparison of Economic Development Discount Allocation

Comparison of Economic Development Discount Allocation[145]				
Allocation Method	Residential	C&I Non-Demand	C&I Demand	Lighting
2013 Rate Case Method[146]	32.3%	3.5%	64.0%	0.2%
100% Energy / Sales (DOC, OAG)	28.1%	3.1%	68.2%	0.6%
Present Revenues (Company, XLI)	35.9%	3.8%	59.4%	0.9%
Present Base Revenues (MCC)	39.2%	4.0%	55.6%	1.2%

ALJ's Conclusion

The ALJ stated her conclusion as follows:

> 753. The Administrative Law Judge concludes that the Company's use of the present revenue allocator in its CCOSS is the most reasonable of the three proposals for allocating the cost of economic discounts because the discounts benefit all customers. Recovering the costs based on present revenues recognizes that keeping these large customers on the system provides an overall benefit to all customers. In the view of the Administrative Law Judge, neither the straight energy method nor the present base revenue method better reflect the benefit of the retention of large customers.

143 Pollock Rebuttal at 22-23.
144 Xcel Post-Hearing Brief at 136.
145 ALJ's Report, p. 171.
146 This is Staff's terminology. As noted in this briefing paper, Xcel has referred to it as "61 percent weighting of the capacity allocator and a 39 percent weighting of the energy allocator," and as "57% Capacity / 43% Energy." The ALJ has referred to it as "60% Capacity / 39% Energy" (See p. 171 of the ALJ's report).

OAG's Exception to the ALJ's Conclusion

The OAG argues the ALJ's reasoning is flawed because it attempts to allocate these credits based on their perceived benefit to customer classes, rather than their cost. Since these discounts are provided exclusively to the large customer classes, and because the amount of the discounts varies with energy consumption, the costs of lost revenues are attributable to energy.

For these reasons, the OAG takes exception to Finding 753 and recommends the following modifications:

> 753. ~~The Administrative Law Judge concludes that the Company's use of the present revenue allocator in its CCOSS~~ The proposal of the OAG and the DOC to allocate cost of economic discounts on the basis of a straight kWh energy allocator is the most reasonable of the three proposals for allocating the cost of economic discounts ~~because the discounts benefit all customers.~~ **Recovering the costs based on present revenues recognizes that keeping these large customers on the system provides an overall benefit to all customers.** ~~In the view of the Administrative Law Judge, neither the straight energy method nor the present base revenue method better reflect the benefit of the retention of large customers.~~ This proposal recognizes that the costs of providing these economic discounts are caused by the amount of energy consumed by large customers.

> **Staff Comment**: The Sentence in bold above is in the ALJ's ¶ 753, but not included in the OAG's revision.

Options

C. vii. 1. Adopt the ALJ's conclusion and recommendation.

C. vii. 2. Adopt the OAG's exception presented above.

(Note: These decision alternatives correspond to alternatives IV, B, 8 (a and b) on pp. 30-31 of the deliberation outline.)

C. viii. Allocation of Interruptible Rate Discounts

Introduction

Xcel treats interruptible discounts as a cost of peaking capacity and allocates that cost to classes based on firm loads. Xcel views interruptible service as firm service with an attached, after-the-fact, purchased-power contract provision.[147] Xcel allocates the costs to customer classes based on firm loads.

The ALJ provided the following overview of the interruptible rate discounts:

[147] Peppin Direct at 7.

> 754. Under an interruptible rate arrangement, a utility has the option to buy back all or part of a participating customer's firm service when doing so is a cost- effective way for the utility to achieve peak capacity. In turn, the utility provides credits to the customers who choose to participate in the program. The Company treats interruptible credits in its CCOSS as a power supply cost of peaking capacity, analogous to the costs of a PPA or its own generation. It allocates the cost of service (including the costs of buying peaking capacity from interruptible customers) to the customer classes to determine rates for firm service. The Company then provides the credits from the firm service rate to the interruptible customers.

Parties' Position (XLI was the only party to comment on this issue)

XLI opposes Xcel's treatment of interruptible credits in the CCOSS. XLI believes Xcel's treatment of these credits violates the matching principle.[148] The ALJ captured XLI's position, thus:

> 755. As it has in prior rate cases, XLI argued that the Company's allocation of interruptible rate credits violates CCOSS revenue-to-cost matching principles. Interruptible rate participants pay a lower rate for a level of service that is subject to curtailment and are shown as contributing less to revenue, while the costs are allocated among all classes as if they received firm service.

ALJ's Recommendation

The ALJ indicated that XLI's position has been previously considered and turned down by the Commission:

> 756. XLI's argument has been addressed and answered in prior rate cases. In the 10-971 ORDER, the Commission found as follows:
>
>> In this case, Xcel treats the cost of a demand-side resource, Interruptible service credits, just as it treats the costs of a supply-side resource, such as additional generation or purchased power. That is, it includes the cost of the resource in the cost of firm service, which it may then – in an unrelated transaction – discount for customers willing to endure interruption. T wo actions are discrete and both are appropriate by their own terms.

The ALJ stated her recommendation thus:

> 757. XLI has brought forward no new evidence or argument to support a finding that the Company's treatment of interruptible service credits is unreasonable. Therefore, the Administrative Law Judge recommends that the Commission reject XLI's proposed change to the allocation of interruptible rate discounts.

[148] Pollock Direct at 46.

XLI's Exception to the ALJ's Recommendation

XLI requested that the Commission reject the statements and findings in paragraphs 754 through 757 of the ALJ's report and urged the Commission to replace this portion of the recommendations with direction to Xcel to modify how the CCOSS results are stated by recognizing the impact of load management costs, consistent with XLI's testimony.

Options

C. viii. 1. Adopt the ALJ's recommendation.

C. viii. 2. Adopt XLI's position stated in its exceptions.

(Note: These decision alternatives correspond to alternatives IV, B, 9 (a and b) on p. 31 of the deliberation outline.)