4-2500-19796-2
E-015/GR-08-415

**STATE OF MINNESOTA**
**OFFICE OF ADMINISTRATIVE HEARINGS**

**FOR THE PUBLIC UTILITIES COMMISSION**

| In the Matter of the Application of Minnesota Power For Authority to Increase Electric Service Rates in Minnesota | **TABLE OF CONTENTS TO FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION** |
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The above-entitled matter came on for evidentiary hearing before Administrative Law Judge Bruce H. Johnson on November 12 - 14 and 18 - 20, 2008, at the offices of the Minnesota Public Utilities Commission in St. Paul, Minnesota.

The parties to this proceeding are: ALLETE Corporation d/b/a Minnesota Power Company ("Minnesota Power," "MP," or the "Company"); the Minnesota Department of Commerce/Office of Energy Security (the "OES"); the Minnesota Office of Attorney General -- Residential Utilities Division (the "OAG/RUD"); Large Power Intervenors ("LPI"); the Minnesota Chamber of Commerce (the "MCC"); Energy Cents Coalition ("ECC" or "Energy Cents"); and Boise, Inc. ("Boise").

Samuel Hanson, Thomas Bailey, and Elizabeth Brama, Attorneys at Law, Briggs and Morgan, 2200 IDS Center, 80 South Eighth Street, Minneapolis, Minnesota 55402, and Christopher Anderson, Associate General Counsel, 30 West Superior Street, Duluth, Minnesota 55802, appeared on behalf of Minnesota Power.

Valerie Means and Julia Anderson, Assistant Attorneys General, 1400 BRM Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the OES.

Ron Giteck and William Stamets, Assistant Attorneys General, 900 BRM Tower, 445 Minnesota Street, St. Paul, Minnesota 55101, appeared on behalf of the OAG/RUD.

Robert S. Lee and Andrew P. Moratzka, Attorneys at Law, Mackall, Crounse & Moore, 1400 AT&T Tower, 901 Marquette Avenue, Minneapolis, Minnesota 55402, appeared on behalf of the LPI.

Eric F. Swanson, Attorney at Law, Winthrop & Weinstine, Suite 3500, 225 South Sixth Street, Minneapolis, Minnesota 55402, appeared on behalf of Boise.

Pam Marshall, Executive Director, 823 East Seventh Street, St. Paul, Minnesota 55106, appeared for and on behalf of Energy CENTS Coalition.

Michael Franklin, Director, Minnesota Chamber of Commerce, 400 Robert Street North, Suite 1500, St. Paul, Minnesota 55101, appeared on behalf of the Minnesota Chamber of Commerce.

Commission Analysts Robert Harding, Louis Sickmann, Stuart Mitchell, Michelle Rebholz, and Chris Fittipaldi appeared on behalf of the PUC Staff.

Notice is hereby given that, pursuant to Minn. Stat. § 14.61 and the Rules of Practice of the Minnesota Public Utilities Commission (the "Commission") and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 15 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, Metro Square Building, Suite 350, 121 7th Place East, St. Paul, Minnesota 55101-2147. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions of Law and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument with their filed exceptions or reply. Exceptions should be e-Filed with the Commission.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept, reject, or modify the Administrative Law Judge's recommendations and that said recommendations have no legal effect unless expressly adopted by the Commission as its final order.

## I. GENERAL BACKGROUND.

### A. Jurisdiction and Procedure.

1. On May 2, 2008, MP filed a petition to increase its electric rates in Minnesota. The Commission assigned docket number GR-08-415 to this matter. The Company requested an annual rate increase of approximately $45,023,633, or approximately 9.69 percent. The Company also filed a proposed interim rate schedule requesting that interim rates be made effective on July 1, 2008. On the same date, MP also filed a petition for a base fuel adjustment rate change to become effective contemporaneously with its interim rates. The Commission assigned docket number MR-08-463 to that base cost fuel adjustment petition.

2. Minnesota Power's claimed revenue deficiency in the initial filing was based on a test year of July 1, 2008, through June 30, 2009; an 11.15% rate of return on common equity; an equity ratio of 54.79%; and the application of the resulting overall rate of return of 8.68% to the rate base calculated as $713,096,651.[1]

3. The Company's initial filing, with significant errata filings, came before the Commission on June 12, 2008. The Commission found MP's filing to be incomplete, and further found that the filing would not be in proper form and substantially complete until the Company re-filed its application in a form that corrected all errors, omissions and other deficiencies.[2]

4. On June 12, 2008, the Company filed its Supplemental Rate Case filing (Supplemental Filing) restating the request for a general increase in its electric rates. In the Supplemental Filing, MP sought an annual rate increase of $45,023,320, or approximately 9.5 percent per year over current rates for firm and non-firm sales of electricity.

5. After a hearing on July 15, 2008, the Commission found the Company's filing to be substantially complete as of June 12, 2008, suspended the proposed rates pending a final decision on the merits, and referred the case to the Office of Administrative Hearings for a contested case proceeding. On July 21, 2008, the Commission issued a Notice and Order for Hearing in this matter, and this contested case proceeding ensued. On the same date, the Commission also entered an Order Setting Interim Rates.[3] The Interim Rate Order approved the Company's interim rate proposal and authorized the Company to put interim rates into effect for service rendered on and after August 1, 2008, subject to refunding that portion of the rate not found to be supported in the final rate determination.

6. The Commission's Notice and Order For Hearing identified the following issues:

(1) Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings by the Company?

(2) Is the rate design proposed by the Company, including proposed revisions to customer charges, reasonable?

(3) Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?

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[1] Ex. 14, Morin Direct, at 76; Ex. 17, Stellmaker Direct, at 19; and Ex. 50, Podratz Direct, at 5-11.

[2] Commission Order Finding Filing Incomplete (issued June 20, 2008) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5298323).

[3] Commission Order Setting Interim Rates (issued July 21, 2008) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5369012).

(4) Is the Company's proposed collection of $18.6 million claimed fuel clause undercollection reasonable?

(5) Are the Company's proposed changes to its Rider for Fuel Adjustments reasonable?[4]

7. On July 21, 2008, the Commission also entered an Order in Docket No. 08-463 granting the Company's May 2, 2008, petition for a base fuel adjustment rate change, with the following clarifications:

1. The following issues will be addressed in the rate case proceedings: 1) MP's proposal to recover "lagged fuel clause costs associated with the implementation of the new base cost of fuel"; and 2) its proposed changes to the Rider for Fuel Adjustments.
2. If any significant adjustments to the cost of energy occur as a result of the general rate case, then the base cost of energy may need to be reconsidered and reflected in final rates subsequent to the Commission's decision in the general rate case.[5]

8. On September 26, 2008, the non-Company parties filed Direct Testimony.

9. On October 22, 2008, the Company, OES, and LPI filed Rebuttal Testimony. In Minnesota Power's rebuttal testimony, the Company recognized adjustments to its initial filing, including an increase in operating income by $1.1 million. Other adjustments decreased MP's rate base by $11.1 million to $703.7 million. Based on these adjustments, Minnesota Power revised its claimed revenue deficiency to $41.4 million.[6]

10. The Company, OES, OAG/RUD, MCC, LPI, and Energy Cents filed Surrebuttal Testimony on November 5, 2008. In Minnesota Power's surrebuttal testimony, the Company noted that it had mistakenly reversed one of its adjustments, resulting in a decrease instead of an increase in operating income under current rates. After correcting its mistake, MP revised its revenue deficiency calculation to $39.8 million.[7]

**B. Summary of Public Comments.**

11. Public hearings were held on September 30, 2008, 2:00 and 7:00 p.m. at the Eveleth Range Recreation & Civic Center in Eveleth (45 members of the public attended); October 1,

[4] Commission Notice and Order for Hearing, at 5-6 (issued July 21, 2008) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5369013).
[5] Commission Order Setting New Base Cost of Energy (issued 21, 2008) at 2 https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5369014.
[6] Ex. 54, Podratz Rebuttal Revisions, Sched. 19.
[7] Ex. 56, Podratz Surrebuttal, at 2 and Sched. 2.

2008, 7:00 p.m., at the Itasca Community College in Grand Rapids (20 attended); October 2, 2008, 2:00 and 7:00 p.m., at the Duluth City Council Chambers in Duluth (110 attended); and October 6, 2008, 7:00 p.m., at the Morrison County Government Center in Little Falls (50 attended). A total of seventy-five (75) members of the public participated in the public hearings by speaking. Written comments were accepted until October 17, 2008.

12. In general, Residential class and General Service class customers objected to the Company's proposed increase in rates, particularly the size of the increase. Many retirees living on fixed incomes noted that recent increases in other expenses they incur have made their energy bill less affordable, even without the proposed increase.

13. Some customers had specific suggestions for addressing MP's proposed revenue deficiency. Three customers and one shareholder maintained that Minnesota Power's executive compensation should be reduced before customer charges are increased. One customer objected to any portion of the costs for wind power being covered in rates. Another argued that ALLETE should use profits from its other enterprises to pay for MP's infrastructure costs, rather than raising rates.

14. Regarding rate design, several residential customers noted that MP's proposal would result in a 100% increase in their monthly charge. One customer had trouble distinguishing between the increase in the monthly charge and the overall rate increase. Several residential customers objected to the disparity in percentage increases between classes—particularly, the proposed percentage increase for Residential customers in comparison with the percentage increase for Large Power customers. Those Residential customers suggested that because of the large volume of electricity that Large Power customers purchase, Large Power customers should bear more of the proposed increase. Several customers described their efforts to conserve energy and asserted that this rate increase would nullify their conservation efforts.

15. A resort owner indicated that the proposed increase in the General Service class was too great a burden on small businesses, and the City of International Falls urged the Commission to strike a balance in MP's new rates between the burdens on residential and general service customers and the relatively lighter burden on Large Power customers.

16. A significant number of customers objected to the proposed rate increase as excessive when viewed in combination with the resource adjustment applied to off-peak and regular meter rates and other riders on the bills they were already having to pay. Off-peak customers pointed out that MP's current off-peak rates offer a savings of around 50% from retail rates, but the proposed off-peak rate increase would reduce that savings to around 28%. Many of the off-peak and dual fuels customers emphasized the expense that they have had to incur to obtain their lower rates. Those customers had

expected that they would be able to realize savings on their electric costs, and they objected to MP's dual fuels and off-peak proposals as disincentives to use these programs and as unfair to those customers who had recently incurred significant costs to switch their service.

17. On the other hand, several customers supported the rate increase as necessary to maintain the Company as a good provider of electricity. One customer compared his electricity bill to his tax bill and asserted the he gets more benefit from Minnesota Power than from the government.

18. Harvey Schmitt, Director of Housing Services for Catholic Charities, indicated that as a low income housing provider, his organization cannot raise the rents it charges to cover the proposed increase in the General Service rate because Catholic Charities' rents are capped by the Department of Housing and Urban Development. Catholic Charities proposed that low income housing providers be eligible for the Company's proposed new low income rate.

19. Shareholders generally supported the rate increase as necessary to maintain Minnesota Power's efficiency and dependability. Many of them noted that it had been 14 years since the Company's last rate increase. Minnesota Utility Investors (MUI) urged approval of MP's rate increase as necessary to provide reliable electrical service. MUI noted that the Company's stock is an investment grade security and that it needs to retain that rating to obtain the capital required for developing the alternative energy sources required by 2025. MUI urged approval of an ROE that will allow MP to 1) attract capital at reasonable rates; 2) ensure reliability of electrical service; and 3) allow shareholders a reasonable rate of return, now and in the future.

20. Public comment relating to Minnesota Power's economic development activities is described in Finding 235, below.

## C. Description of the Company.

21. Minnesota Power is an operating division of ALLETE, Inc., which is a Minnesota corporation headquartered in Duluth, Minnesota. In addition to MP, ALLETE has business lines in real estate investment and coal mining. ALLETE estimates that its regulated utility business represents about 94% of the corporation's assets and includes Minnesota Power and ALLETE's Superior Water, Light and Power (SWL&P) subsidiary in northwestern Wisconsin. Minnesota Power generates about 80% of ALLETE's revenues. The Company began generating electricity in 1906 and now provides electricity to 141,000 retail customers in Northern Minnesota.[8] Minnesota Power's

[8] Ex. 10, McMillan Direct, at 3-4.

service area extends approximately from Bemidji, Park Rapids, and Wadena on the west eastward to the shores of Lake Superior and from International Falls on the north southward to Hinckley.

### D. Burden of Proof.

22. Minn. Stat. § 216B.16, subd. 4, imposes on MP the burden of showing "that the rate change is just and reasonable." Minn. Stat. § 216B.03 provides: "Every rate made, demanded or received by a public utility . . . shall be just and reasonable . . . . Any doubt as to reasonableness should be resolved in favor of the consumer."

23. The Minnesota Supreme Court described the Commission's role in determining just and reasonable rates in a rate proceeding as follows:

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[9]

24. In this proceeding, the Administrative Law Judge's role is to assess the evidence presented and make recommendations to the Minnesota Public Utilities Commission. Whether Minnesota Power has met its burden of proof is ultimately for the Commission to decide, based on the record.

## II. TEST YEAR ISSUES.

25. In rate cases before the Commission, utilities determine the extent to which projected revenue will cover the anticipated costs of operation, including a return on investment to shareholders. The period used to measure this revenue and these costs is called the test year. Minnesota Power proposed a projected test year of July 1, 2008, to June 30, 2009. Over that period, MP estimated total operating revenues of $535,814,764, and total utility operating expenses of $497,899,486.[10] MP estimated its rate base as $699,711,856 and proposed a rate of return of 8.68%. To meet that rate of return, MP

[9] *ITMO the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987).
[10] MP Brief, Appendix 2.

calculated a required operating income of $60,734,989. By the Company's calculations, MP will experience a required gross revenue deficiency of $38,921,550 over its test year.

## A. Forecast Test Year.

26. Rather than using an historical calendar year, such as 2007, as a test year, Minnesota Power has proposed a projected test year of July 1, 2008, to June 30, 2009, for its test year in this proceeding. That 12-month period corresponds to Minnesota Power's fiscal year and budget cycle. On the other hand, the OAG/RUD urges the Commission to require the utility to use an historical calendar year as its test year.

27. Minnesota Power explained its reasons for using a projected test year as follows:

> Although a projected test year may turn out to be slightly different than those actual financial results, the question is whether it will be more accurate than the use of a historical test year, adjusted for known change. Because a projected test year incorporates the Company's best estimates of utility plant, sales and financial assumptions for the upcoming year, it is likely a better representation of what will actually occur during the year than an adjusted historical year. Either way, the accuracy depends on the assumptions that are made.[11]

28. The OAG/RUD maintains that using a historical test year, adjusted for known changes, is the superior method for calculating the expenses to be incurred by the utility. The OAG/RUD contends that since the activities that generate most expenses in the utility area are consistent from year to year (as demonstrated by the class customer cost of service study, for example), use of an adjusted historic test year affords the benefits of showing costs that have actually been incurred and allowing those costs to be audited for suitability for recovery from ratepayers.[12]

29. The Commission has described the reasons for using an historical test year, adjusted for known changes, as follows:

> Basing revenue requirements on financial data from a test year, a representative slice of the utility's normal operations, is intended to base rates on experience instead of conjecture. It is also intended to replace the

[11] MP Brief, Appendix 3.
[12] Ex. 76A, Lindell Direct, at 5; Ex. 77, Lindell Surrebuttal, at 4-5.

fiscal discipline of the market place, which is absent for monopolies, with the fiscal discipline of prior determination of reasonable costs.[13]

30. The OAG/RUD's argument for requiring Minnesota Power to use an historical test year is primarily two-fold. First, it argues that since the Company will not be able to provide actual data on a jurisdictional basis for the early months of the test year, the parties will not be able to determine the accuracy of the Company's forecasting for that portion of the test year.[14] Second, it argues that the unreliability of the Company's projected test year is established by a retail sales forecast for the projected test year that is unreasonably low—that is, a $54 million decrease in test year sales in comparison with 2007 retail sales without a reasonable explanation.[15]

31. While acknowledging that its methodology does not provide actual data on a Minnesota jurisdictional basis, the Company maintains that its FERC financial reporting did provide "[t]otal Company data for relevant timeframes which will indicate overall trends in revenues and expenses … [that] would indicate the relative accuracy of the Minnesota jurisdictional amounts included in the rate filing."[16] The Company further argues that using a historic test year, adjusted for known changes, would be flawed, since that process would "virtually [convert] the historic test year into a projection … in an *ad hoc* manner, failing to provide the benefits of using a budget that systematically and comprehensively considers all changes that will impact the test year." Minnesota Power also maintains that use of "a historic test year does not really narrow the issues in a rate case."[17]

32. Whether the Company's revenue projections for a test year are unreliable or unreasonably low does not depend on whether the test year is historical or projected. In either case, the reliability of sales forecasts depends primarily on the reliability of the forecast methodology and inputs. For example, in this proceeding, the ALJ has found that some of Minnesota Power's sales forecasts were unreliable because the forecasting methodology is less reliable than other approaches.[18] If the Commission agrees with those findings, those forecasts would be unreliable regardless of what test year the Company used.

33. Finally, the use of a projected test year, including the use of split test years, has been common and has been approved by the Commission in other rate cases. Minnesota Power itself

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[13] *ITMO the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota*, Docket No. E002/OR-89-865, Order Denying Petitions for Reconsideration and Denying Transitional Rate Increase (November 26,1990).
[14] Ex. 76A, Lindell Direct, at 7.
[15] OAG/RUD Brief, at 12.
[16] Ex. 25, DeVinck Rebuttal at 3.
[17] MP Brief, at 10.
[18] *See, e.g.,* Findings 48, 55, and 60.

used split projected test years in five of its previous seven cases: GR-87-223 (July 1, 1987 – June 30, 1988); GR–81- 250 (July 1, 1981 – June 30, 1982); GR-80-76 (May 1, 1980 – April 30, 1981); GR-78-514 (July 1, 1978 – June 30, 1979); and GR-77-360 (May 1, 1977 – April 30, 1978).[19]

34. Whether there are deficiencies in some of the Company's specific cost and revenue forecasts will be analyzed in other Findings. Nonetheless, even though an historic test year may be generally superior, particularly regarding expenses, the OAG/RUD has not demonstrated that the mere use by Minnesota Power of a projected test year has created a bias toward maximizing a forecast revenue deficiency. In view of all of the above, the ALJ therefore concludes that the Company's use of a projected test year from July 1, 2008, to June 30, 2009, is reasonable, and that the Commission should allow it.

## B. Sales Forecasts.

### 1. General Approach to Forecasting Sales Used by Minnesota Power.

35. Minnesota Power's test-year sales are forecast for the last six months of 2008 and the first six months of 2009, which correspond to the utility's current fiscal year. The Company employed multiple forecasting techniques to estimate its test-year sales and revenue projections for its various customer classes. It relied in whole or in part on its econometric Advance Forecast Report ("AFR") for five customer classes—i.e., the Residential, General Service, Large Light and Power,[20] Municipal Pumping, and Dual Fuels classes;[21] it relied solely on specific monthly load forecasts for its Large Power class and on historical data for its Lighting class.[22] With the exception of Large Light and Power, Lighting, and Large Power classes, the usage of all of those classes is strongly affected by weather patterns.[23]

36. More specifically, the test year sales and revenue figures forecast by MP for all but Large Power customers were estimated using a budget forecasting program that is primarily based on annual sales and revenue estimates from its AFR, which MP then allocated to months in the test year using MP's monthly budget forecast. However, as previously noted, Minnesota Power is unique in that roughly 70 percent of its sales are to customers having steady energy usage patterns that are not affected significantly by weather.[24] Rather than using econometric modeling or specific load forecasts, the Company used marketing forecasts for its Large Power class customers, whose usage

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[19] MP Brief, at 9.
[20] For both its General Service and its Large Light and Power classes, the Company forecasts its sales using both its AFR forecast and specific monthly load forecasts. Ex. 90B, Heinen Direct Exhibits, AJH-3.
[21] *Id*.
[22] *Id*.
[23] Heinen Direct, Ex. AJH-3 at 2.
[24] *Id*.

is relatively consistent and production-based.[25] In developing test year forecasts of monthly sales and revenue projections for those customers, MP consulted with each of them individually to produce marketing forecasts.[26]

37. To estimate test year sales for classes for which it relied on its utility budget forecasting program, MP began by producing two separate and independent forecasts, one using a monthly econometric model and the other using an annual econometric model. Both are time series econometric models that incorporate serial correlation. One respect in which they differ is that the monthly model uses data over the 1993 to 2007 time frame, while the data for the annual model uses data from 1965 through 2007, with the estimation conducted over the time frame beginning in 1969 forward.[27] The two models arrived at two different results. MP then used the results of the monthly model to convert the projected annual sales volumes AFR model into monthly estimates that form the basis for the retail sales forecasts for weather-sensitive customer classes.[28]

38. Other Minnesota utilities generally use only an econometric monthly budget forecast to estimate test year monthly sales. Nonetheless, although unorthodox, the Company's forecasting methodology of using its monthly budget forecast to allocate the results of its AFR to months in the test year does not violate industry standards.[29] The estimation techniques and processes used in the Company's AFR are similar to the 15-year load and sales forecast employed by Minnesota Power in its Integrated Resource Plan.[30]

39. Minnesota Power projected its test-year sales estimates for individually billed customers based on specific load forecasts, historical usage data, or marketing information on prospective energy usage provided by customers to the Company's marketing department, although in some cases that information was correlated with statistical methods.[31] Given Large Light and Power customers' power usage characteristics (generally shifting between months) and the amount of available monthly data, statistical forecasting techniques are not appropriate and may produce unreasonable test-year forecasts.[32]

40. In its analysis of the Company's forecasts for its seven Large Light and Power customers, the OES prepared a visual sales analysis for each Large Light and Power customer from January 2000 through the end of Minnesota Power's budget forecast in December 2009. After examining those historical sales patterns to ensure that sales have been

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[25] OES Ex. 90A at 14, 32 (Heinen Direct).
[26] *Id*.
[27] Tr. Vol. 2, at 123-124 (Camfield).
[28] Tr. Vol. 2, at 129-135 (Camfield).
[29] Ex. 90A, Heinen Direct, at 7; Tr. Vol. 5 at 84.
[30] Ex. 90A, Heinen Direct, at 4, citing Docket No. E015/RP-07-1357.
[31] Ex. 90A, Heinen Direct, at 23; Ex. 90B, Heinen Direct Exhibits, AJH-3.
Ex. 90A, Heinen Direct, at 24.

consistent for those customers, the OES established a three-year average of actual energy usage for each affected customer. The OES then charted line graphs of historical usage for each customer and projected usage during the two budget years (2008 and 2009, which includes the test-year). Based on that graphical analysis, the OES concluded that the test-year sales forecasts for two LLP customers had been underestimated, and it recommended an upward adjustment of the sales to those seven customers.[33]

41. Approximately 70 percent of Minnesota Power's sales are to a small group of Large Power customers in the forest products and taconite industries whose operations are energy intensive.[34] The usage patterns of those customers tend to be relatively consistent and unaffected by weather but are significantly affected by demand for wood products, paper, and taconite, which can significantly affect annual production levels. Accordingly, it is reasonable for the Company to primarily rely on consultations with individually billed Large Power customers to produce marketing forecasts of test-year monthly sales and revenue projections.

### 2. Forecasts of Sales to Residential Service, General Service, Municipal Pumping, and Dual Fuel Classes.

42. The OAG/RUD challenged the Company's forecast of residential and general service revenues on the grounds that the test year sales to these classes were lower than historical data would support.[35] It noted that in 2007, Minnesota Power had "actual sales [that] were 8% greater than what were budgeted for the year 2007. Actual revenues for 2007 were $49 million higher than budget, which is more than the $45 million increase that the Company is requesting in this case." 36 The OAG/RUD further noted that the Company's own comparisons of its operating revenues, expenses and operating income for the Minnesota jurisdiction for historical 2007, projected 2008, and the test year (2008-2009) showed a decline of approximately $54 million in sales, from 2007 to the test year. This represents a 9 percent reduction from 2007. The OAG/RUD maintains that MP has provided "no clear explanation … for such a monumental decline in sales, and it appears to be at variance with other data."[37] The OAG/RUD noted that historically, MP has not experienced a decline in sales for either the Residential or General Service customer classes. The OAG/RUD also pointed to the fact that ALLETE's 10-Q Report for the period ending June 30, 2008, contains the following comparison of the six months ending June 30, 2008, with the same period ending June 30, 2007:

[33] Ex. 90A, Heinen Direct, at 22-23; Peirce Surrebuttal at 5.
[34] Ex. 10, McMillan Direct, at 8-9; Ex. 90A, Heinen Direct, at 4.
[35] Ex. 76A, Lindell Direct at 15-18.
[36] Ex. 76A, Lindell Direct, at 6; Ex. 76B, Lindell Direct Exhibits 1-9, JLL-1.
[37] OAG/RUD Brief, at 11.

> *Operating revenue* decreased $2.4 million from 2007, primarily due to decreased fuel clause recoveries and the reduction in revenue from sales to Other Power Suppliers.
>
> Fuel Clause recoveries decreased $15.0 million in 2008 primarily as a result of decreased power expenses reflecting increased Company generation and increased hydro availability.[38]

43. In rebuttal, Minnesota Power argued that its sales do not increase or decrease simply because of the passage of time, but rather because of specific factors that are determinative of the amount of energy a class of customers will use.[39] The Company went on to identify four factors that it believes are more relevant than historical sales data in forecasting sales to the Residential and General Service customer classes: namely, the increase in the price of electricity, the decrease in the price of natural gas, per capita income, and area employment.[40] The Company also addressed how it believed that each one of those factors indicated reduced energy consumption among residential and general service customers for the test year.[41] MP then argued that the OAG/RUD had failed to address the significance of those indicators in forecasting class sales.

44. While acknowledging MP's responses, the OAG/RUD still emphasized "that sales exceeded budget by an amount tantamount to the entire proposed rate increase, whatever the particular cause." 42 The OAG/RUD's approach to test year sales forecasts, however, presents difficulties. First of all, since the sales estimates developed for any test year, regardless of whether it is an historical or projected test year, will be the basis for the utility's rates for the future, any historical sales revenue data incorporated into test year revenues will necessarily impact the estimate or forecast. The issue, however, is whether the utility's revenue projections for the test year are reliable, not necessarily how they correlate to specific historical data. The OAG/RUD's position also seems predicated on the assumption that in order to be reliable, test year revenue estimates must always correlate with actual historical usage. Implicit in that assumption is that using econometric models to forecast sales to customer classes whose usage is dependent on such factors as weather, the price of electricity, the price of natural gas, per capita income, and area employment,[43] is conjectural and unreasonable, which is clearly not the case.

45. Although the OES was also troubled by the disparity between test year estimates for the residential and general service classes, its challenge to MP's retail sales and revenue

[38] Ex. 77, Lindell Surrebuttal, JLL-1 (italics in original).
[39] Ex. 28, Norberg Rebuttal, at 7.
[40] *Id.*
[41] *Id.* at 7-8.
[42] OAG Brief, at 11.
[43] Ex. 28, Norberg Direct, at 7.

forecasts for those classes is more specific and technically based than the OAG/RUD's challenge. The OES agrees with the OAG/RUD that since the econometric forecast method that MP used to estimate test year sales of non-Large Power classes included an estimate of 2007 annual sales, it should correlate well to the to actual sales from the Company's 2007 Annual Jurisdictional Report. The OES, however, then proceeded to compare the Company's 2007 AFR and monthly budget process forecasts to weather-normalized actual sales from the Company's 2007 Annual Jurisdictional Report.[44] Based on that comparison, the OES concluded first that MP's 2007 AFR forecast did not correlate well to actual weather-normalized sales. From that comparison, the OES also concluded that the Company's AFR method underestimated the sales of all classes (other than Lighting) for the test year. The OES therefore recommended that the Company's AFR model should be rejected for ratemaking purposes because it does not produce reasonable results and would cause rates for MP's ratepayers to be unreasonably high until the Company files a new rate case.[45] Additionally, based on the comparisons that the OES made, it concluded that the Company's monthly budget forecast produced representative test-year sales estimates that were more reliable for setting just and reasonable rates in this proceeding. Accordingly, the OES advocates use of MP's monthly budget process models to project sales and revenues for these customer classes.

46. Minnesota Power takes issue with the OES's conclusions arguing that although the Company's AFR model may have produced a forecasting error for 2007, it fails to establish that the model is inherently biased. The Company points out that all forecasting models produce forecasting errors without necessarily having a forecasting bias. In order to determine the presence of bias, one would need to analyze the forecasts for a number of years. For unbiased forecasting models, one would see both over-predictions and under-predictions over those years, with the average forecasting error close to zero. The Company argues that the OES's analysis does not involve any demonstration of a consistent under-estimation of sales over a number of years that can only be explained by systemic forecasting bias.[46]

47. It appears from the record that Minnesota Power has only been using its current AFR methodology for annual sales forecasts since 2006, and that the deviation of actual from forecast values in 2006 was +.15%, resulting in an average forecast error for the two years of usage of – 1.14%.[47] On the other hand, over ten years of usage, the Company's monthly budget forecast error has only averaged +.29%. In the ALJ's view, the sales and revenues for the Company's residential and general service classes should be estimated using Minnesota Power's monthly budget process models, as the OES recommends, rather than using the Company's approach of using that monthly model only to calibrate the annual sales volumes projected by its AFR model. Other

[44] Ex. 90A, Heinen Direct, at 14-16.
[45] Ex. 92, Heinen Surrebuttal, at 9.
[46] Ex. 32, Camfield Rebuttal, at 15.
[47] *Id*. at Schedule 1.

Minnesota utilities rely on the monthly budget process model to estimate test year sales, and the record establishes that over the last ten years, Minnesota Power's monthly budget process model has established long term reliability by demonstrating an average annual forecast error of only 0.29%. Although the fact that Minnesota Power's 2007 AFR forecast did not correlate well to actual 2007 weather-normalized sales does not establish bias in that forecast method, the fact that the Company has only two years of experience with that method is insufficient to establish its reliability and lack of bias.

48. Finally, Minnesota cites a downturn in the economy as justification for accepting its econometric approach for forecasting sales to residential and general service classes.[48] The problem with that argument is that, by most accounts, what is likely to happen with the economy in the near term is still largely unknown, speculative, and not yet susceptible of reliable econometric analysis. Attempting to validate an econometric forecasting method, the reliability of which is relatively untested, with a qualitative perception about the economy simply introduces an element of subjectivity into what should be an objective forecast. Based on all of the considerations set forth above, the ALJ concludes that the Commission should accept the OES's approach and results for forecasting Residential and General Service sales during the test year rather than Minnesota Power's approach and results.

### 3. Forecasts of Sales to Large Light and Power Classes.

49. Minnesota Power's Large Light and Power customers are individually billed, and the test-year sales estimates for those customers are projected by the Company's marketing department, not solely by statistical methods.[49] Usage by those Large Light and Power customers tends to be relatively stable and predictable, since their usage would not normally be significantly affected by either weather[50] or by changes in market conditions, to the extent of Large Power customers.

50. After reviewing the test year sales forecasts of Minnesota Power's individually billed Large Light and Power customers, the OES concluded that MP's test-year estimates for two of those customers, Ainsworth and Polymet, did not correspond with historical usage patterns and sales trends— specifically, it concluded that the forecast test year sales appeared unreasonably low in comparison to the 3- and 8- year averages of past sales to those customers.[51] The OES therefore concluded that the test year sales estimates for those customers had been underestimated.[52] To correct for that underestimation, the OES recommends a somewhat higher sales forecast for these customers.

[48] MP Reply Brief, at 15-16.
[49] Ex. 90A, Heinen Direct, at 23.
[50] Ex. 90A, Heinen Direct, at 4.
[51] Ex. 91A , Heinen Direct (Trade Secret), at 24-25; Ex. 116, Peirce Surrebuttal, at 5-6.
[52] *Id.*

51. In rebuttal testimony and based on a recent public announcement by Large Light and Power customer Ainsworth-Grand Rapids (Ainsworth) of its permanent shutdown of production, Minnesota Power proposed a downward adjustment of the sales forecast for Ainsworth that was significantly lower than what the Company had even previously forecast.[53] Specifically, the evidence indicated that the customer would be indefinitely shut down along with the other Minnesota plants of its parent company and that it has no current prospects of opening again. That change will represent a significant decline in retail sales to Ainsworth.[54] Nevertheless, the OES objected to that further downward adjustment on the ground that the information in the record was insufficiently detailed to support the downward adjustment.[55]

52. On the other hand, the Minnesota Power did not otherwise respond specifically to the OES's observation that test year forecasts for Polymet did not correspond with historical usage patterns and sales trends. Rather, the Company only responded that it had worked with its Large Light and Power customers directly to get the best information about their needs so that sales forecasts will be as realistic as they can be.[56] The Company neither argued with nor offered support for the OES's proposed adjustments to the Company's forecasted sales for Polymet.[57]

53. In response to the evidence that the Company had presented regarding Ainsworth, the OES modified its position by accepting MP's original forecast of that customer's sales, but the OES did not agree to a further reduction based on the Company's customer-specific information on the basis that sales forecasts for a test year should be based on conditions during a "normal" year and not on the occurrence of unique events.[58]

54. The Commission has described its approach to test year adjustments as follows:

> As a general rule, the Commission is reluctant to adjust revenue requirements to reflect changes, certain or not, unless there is a compelling need to do so. This is because the test year method by which rates are set rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical -- some favoring the Company, others not. Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year process. Anomalies are likely to exist in and beyond any test year.

[53] Ex. 63, Ainsworth press release; Ex. 93, Heinen Surrebuttal, at 22; Ex. 116, Peirce Surrebuttal, at 5-6.
[54] Ex. 29, Norberg Rebuttal (Trade Secret), at 9-10.
[55] Tr. Vol. 5 at 96-97 (Heinen).
[56] Tr. Vol. 4 at 21 (Selecky).
[57] *Id*
[58] Ex. 93, Heinen Surrebuttal (Trade Secret), at 18.

In keeping with these general principles, the Commission has adjusted for changes in the past only when their certainty and magnitude would otherwise make the test year process unreliable.[59]

55. Although Large Light and Power customers are individually billed and their test year sales are therefore based on customer marketing forecasts, sales to those customers tend to be more predictable than sales to Large Power customers because usage tends not to be subject to fluctuations in demand or production. It is therefore reasonable to expect usage for Large Light and Power customers to rise or fall according to historically established trends, absent evidence of occurrences that would justify a departure from those trends in the test year. In this proceeding, Minnesota Power only presented evidence of such an occurrence with respect to one of its Large Light and Power customers. Although the sales forecast for Ainsworth – Grand Rapids should be adjusted downward as advocated by Minnesota Power to correspond to the evidence establishing a departure from the trend for that customer, the Company's sales forecasts for Polymet should be adjusted upward as recommended by the OES.

**4. Forecasts of Sales to the Large Power Class.**

56. The OES objected to Minnesota Power's initial test year sales and revenue forecasts for a select number of individually billed customers, including one Large Power customer (Customer X), as being unreasonable because the test-year sales and revenues were noticeably lower than sales and revenues during the 12-month period prior to the test year. The OES examined Customer X's historical sales and calculated three-year and eight-year sales averages. Concluding that its two average sales calculations were a clear indication that test-year sales for Customer X had been underestimated, the OES proposed an adjustment increasing the sales forecast usage for that Large Power customer.[60]

57. In September 2008 Minnesota Power entered into an agreement with Cleveland-Cliffs, now known as Cliffs Natural Resources, Inc., providing for contract extensions and amendments to the Electric Service Agreements with Hibbing Taconite and United Taconite. Although MP did not project both companies' total power usage to change substantially from what was assumed in the test year sales forecast, the Company indicated that relative quantities of Large Power firm and interruptible energy usage have changed as a result of recent changes in Minnesota Power's incremental/market-based price of interruptible energy compared to the firm energy price. Minnesota Power asserts that those changes resulted in decreases in projected test year revenues from

[59] *ITMO the Petition of Minnesota Power & Light Co., d/b/a Minnesota Power, for Authority to Change its Schedule of Rates for Retail Electric Service in the State of Minnesota,* Docket No. E-015/GR-87-223, at 3 (Commission Order after Reconsideration and Rehearing issued May 16, 1988) (http://www.puc.state.mn.us/portal/groups/public/documents/puc_pdf_orders/001421.pdf).

[60] Ex. 90A, Heinen Direct, at 28.

the projections in the original case filing.[61] Additionally in June 2008, Enbridge Energy entered into a new Electric Service Agreement ("ESA") providing for electric service under Minnesota Power's Large Light and Power rate rather than the previous discretionary rate pipeline service. This Agreement was filed with the Commission for approval on August 18, 2008, in Docket No. E-015/M-08-976. The revenues under Minnesota Power's new Agreement with Enbridge are projected to be lower than those assumed under the pipeline discretionary rates that were in place at the time of the rate case filing. Minnesota Power is therefore seeking downward adjustments of its initial sales forecasts for those customers.[62]

58. The OES also objects to the proposed downward adjustments to Hibbing Taconite, United Taconite, and Enbridge. It argues that none of the three ESAs Minnesota Power lists have been approved by the Commission. Therefore, there is no guarantee that the revenue effects that Minnesota Power recommends will occur. Second, since the agreements do not involve changes in sales levels, only modifications in revenues from those customers, Minnesota Power has a burden to show why all other customers on Minnesota Power's system should have to subsidize these customers by paying higher rates to offset their revenue reductions. In other words, the OES argues that inclusion of those adjustments on a total system level would unreasonably burden all other Minnesota Power ratepayers.[63]

59. As noted above, "the Commission has adjusted for changes in the past only when their certainty and magnitude would otherwise make the test year process unreliable."[64] With regard to the adjustment the OES proposes for the sales forecast for the single Large Power customer (Customer X), the adjustment appears based on a reduction in usage. Business cycles are not regular and predictable, and near term future market conditions and customer production levels do not necessarily have a predictable relationship with historical market conditions and customer production levels, even those in the recent past. Minnesota Power's forecasts of a reduction in that Large Power customer's sales for the test year, and also for the life of a three-year rate, if that is what the Commission orders, are consistent with the evidence that was presented concerning market conditions for each of the Large Power customers during the test year and extending into the near future. The ALJ therefore recommends that the Commission approve that adjustment.

60. On the other hand, the Company's proposed downward adjustments in sales forecasts for Hibbing Taconite, United Taconite, and Enbridge present a different situation; they are

[61] Ex. 52, Podratz Rebuttal at 17.
[62] *Id*. at 15-16.
[63] Ex. 92, Heinen Surrebuttal at 23-24.
[64] *ITMO the Petition of Minnesota Power & Light Co., d/b/a Minnesota Power, for Authority to Change its Schedule of Rates for Retail Electric Service in the State of Minnesota,* Docket No. E-015/GR-87-223, at 3 (Commission Order after Reconsideration and Rehearing issued May 16, 1988) (http://www.puc.state.mn.us/portal/groups/public/documents/puc_pdf_orders/001421.pdf).

based on a reduction in rates, and not usage. It is therefore less clear that those proposed revenue reductions are based on economic conditions. Moreover, their certainty and magnitude are currently less predictable and dependent on future actions of the Commission, which will be based, in part, on their impact on other ratepayers. The ALJ therefore recommends that the Commission approve the Company's sales forecasts for its Large Power customers, but disapprove MP's proposed adjustments for Hibbing Taconite, United Taconite, and Enbridge.

61. The OAG/RUD's more general objection to the Company's sales forecasts for Large Power customers assumes that marketing forecasts are necessarily less reliable than relying on past usage adjusted for inflation. However, that position does not account for the possibilities that large power customers may experience reasonably foreseeable long term or permanent changes in requirements or changes in production during the life of the rate increase being sought. The ALJ therefore recommends that the Commission not rely on the OAG/RUD's approach to downward adjustment of Large Power customer sales forecasts, which is based on historical sales subject to an annual adjustment for inflation.

## III. RATE OF RETURN.

### A. General Principles.

62. In the competitive market environment, prices and operating incomes are determined by the free interaction of market forces, such as supply and demand. Those market forces define the optimal levels and mix of the variety of goods and services that are produced in the economy. In rate-regulated industries, prices (described as rates) and operating incomes (returns) are determined by regulatory agencies. Those agencies must set reasonable rates to ensure such utilities are financially able to provide an adequate supply of satisfactory services. Providing those services is dependent, in part, on a utility's ability to compete for necessary funds in the capital markets. The utility must earn enough to offer competitive returns to investors in order to attract those funds. In the regulated utility context, a fair return enables the utility to attract sufficient capital to conduct business, at reasonable terms.[65]

63. The Commission has consistently followed a number of principles in determining appropriate rates of return (ROR) in utility rate setting proceedings. Those principles can be briefly stated as:

- The rate of return should be sufficient to enable the regulated company to maintain its credit rating and financial integrity.

[65] Ex. 118, Amit Direct, at 2.

- The rate of return should be sufficient to enable the utility to attract capital.

- The rate of return should be commensurate with returns being earned on other investments having equivalent risks.[66]

64. One determines ROR by calculating the weighted average cost of the various sources of capital used by a company. The weighting converts the sources of capital (debt or equity) to the percentages reflected in the company's capital structure. Capital structure generally refers to the mix of long- and short-term debt, preferred stock, and common equity that constitute those sources of capital. To reflect the impact of the different cost of various types of capital, each component is weighted by its relative proportion in the overall mix of capital to determine the overall cost of capital. Calculation of the overall ROR requires a determination of costs and types of capital used by the company.[67]

## B. Capital Structure.

65. Minnesota Power has no legal existence separate from its parent company ALLETE and therefore has no publicly-traded common stock.[68] Since there is no market-driven balance between debt and equity securities to assess MP's capital structure, other approaches must be employed to strike that balance.

66. Minnesota Power followed Standard & Poor's (S&P) and Moody's benchmarks for debt to capital (equity) ratio ranges to retain ALLETE's current BBB+ financial rating, adjusted by debt equivalents.[69] The Company did not conduct any comparison of its proposed capital structure with the utility operating divisions or subsidiaries of comparable companies. Rather, the Company compared its estimate of debt equivalents to those held by other investor-owned utilities.[70]

67. Minnesota Power's assessment concluded that its capital structure should be comprised of 54.79% common equity and 45.21% long-term debt.[71] The Company maintains that its proposed test year capital structure was reasonable and appropriate for the following reasons:

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[66] Ex. 118, Amit Direct, at 2 -3 (*citing Bluefield Water Works & Improvement Company vs. Public Service Commission of the State of West Virginia*, 262 U.S. 679 (1923)(*Bluefield*) and *Federal Power Commission vs. Hope Natural Gas Company*, 320 U.S. 591 (1944)(*Hope*)); Ex. 14, Morin Direct, at 14-16 (citing *Bluefield* and *Hope*).
[67] Ex. 118, Amit Direct, at 49.
[68] MP does have an "accounting-capital stucture" separate from ALLETE, but that does not provide the information needed for these calculations. Ex. 118, Amit Direct, at 50.
[69] Ex. 17, Stellmaker Direct, at 10-14.
[70] Ex. 17, Stellmaker Direct, at 16-17.
[71] Ex. 17, Stellmaker Direct, at 19.

> The Company's objective is to maintain adequate investment grade credit ratings in order to continue to access the capital it needs at reasonable costs. The substantial capital expenditure requirements facing Minnesota Power make this objective both more difficult and more important. The Company's recommended test year capital structure produces capital ratios somewhat inferior to ratios consistent with ALLETE's current S&P credit rating. ALLETE will need to issue additional equity in the test year and beyond to generate adequate credit metrics while it funds Minnesota Power's capital requirements, and the Company has communicated to rating agencies its plans to finance these capital requirements with a combination of debt and equity issuances that will produce capital structures supporting ALLETE's current S&P credit rating.[72]

68. The OES compared MP's proposed capital structure to the average capital structure for other similar utilities. The OES noted that the average 2007 equity ratio for the comparable group of electric companies (used to determine the OES's proposed ROE) is 47.88 percent. Using a standard deviation of the equity ratios for that group results in a range of 41.58 percent to 54.18 percent. Similarly, the average 2007 equity ratio for the OES-determined comparable group of combined gas and electric companies (less one outlier company) is 51.14 percent. Based on these comparisons, the OES concluded that MP's proposed equity ratio of 54.79 percent is too high.[73]

69. The OES conducted an analysis of MP's appropriate equity ratio, using the S&P factors that were identified in MP's analysis. OES arrived at a common equity figure of 52.11 percent.[74] The parties' competing proposed capital structures are as follows:

| | MP Proposal | OES Proposal |
|---|---|---|
| Long Term Debt | 45.21% | 47.89% |
| Common Equity | 54.79% | 52.11% |
| Total | 100.0% | 100.0% |

70. The OES proposal adjusts the imputed capital structure for MP to put more of the structure into long-term debt, which is currently lower in cost than equity. This adjustment results in a reduction of the overall revenue required to meet the ROE figure. The OES further recommended that MP be organized as a separate subsidiary that is wholly owned by ALLETE (rather than an operating division).[75]

71. It is not appropriate to consider ALLETE's needs in imputing an appropriate capital structure to

[72] Ex. 17, Stellmaker Direct, at 14.
[73] Ex. 118, Amit Direct, at 51-52.
[74] Ex. 118, Amit Direct, at 52-56.
[75] OES Brief at 43-45; Tr. Vol. 5 at 63.

MP. The capital structure must be reflect the economic structure of the utility operations for which ROR and ROE are being calculated. In this instance, the paramount consideration is striking an appropriate balance between the cost of capital that a business should reasonably incur while maintaining a respectable rating for the issuance of securities. The OES has shown that its proposed mix of debt and equity meets these dual considerations better than MP's proposal.[76] The OES has therefore demonstrated that its proposed capital structure is appropriate for the ROR and ROE calculations in this proceeding.

## C. Competing Determinations of ROE.

72. In its rate-setting orders, the Commission has balanced ratepayer and utility interests. This balancing is required to carry out the Commission's statutory responsibility to set rates that are just and reasonable. A reasonable rate enables an investor-owned utility to recover its operating expenses, depreciation, and taxes, as well as compete for funds in capital markets. Allowing a fair and reasonable return upon the utility's investment in property used to provide the utility service is a factor in setting just and reasonable rates. This return on investment in property is more commonly referred to as return on equity ("ROE").[77]

73. For publicly-traded companies, ROE is determined by the actual performance of that company's stock in the marketplace. Since ROE is a market-based concept and Minnesota Power does not exist in the marketplace except as an operating division of ALLETE, it is necessary to establish the ROE figure for Minnesota Power by other means. The Commission has historically relied upon the Discounted Cash Flow ("DCF") analysis to derive ROE for rate cases. This is the most widely accepted model and one that has been used consistently as a starting point for establishing the cost of equity in public utility cases before the Commission.[78]

74. The basic standards for the determination of ROE are set forth in *Hope*[79] and *Bluefield*[80] and in Minn. Stat. § 216B.16. *Hope* and *Bluefield* establish standards that require a return that is: (1) consistent with other businesses having similar or comparable risks; and (2)

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[76] Ex. 118, Amit Direct, at 15.
[77] *ITMO the Application of Otter Tail Corporation d/b/a Otter Tail Power Company, for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E017/GR-07-1178 (Commission Findings of Fact, Conclusions of Law, and Order issued August 1, 2008)(*Otter Tail Power 2008 Order*) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5408013 ); *ITMO the Application of Northern States Power Company, a Minnesota Corporation and Wholly Owned Subsidiary of Xcel Energy Inc., for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-002/GR-06-1429, at 28 (Commission Findings of Fact, Conclusions of Law, and Order issued September 10, 2007)(*NSP Gas Rate 2007 Order*). (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=4768622).
[78] *NSP Gas Rate 2007 Order*, at 28.
[79] *Hope,* 320 U.S. at 603.
[80] *Bluefield*, 262 U.S. at 692-93.

adequate to support credit quality and access to capital, while maintaining financial integrity. Minn. Stat. § 216B.16 refers to "the need of the public utility for revenue sufficient to enable it … to earn a fair and reasonable return upon [its] investment … ."

75. The Commission's order should provide the Company with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure the financial soundness of the Company's operations; and (3) commensurate with returns on investments in utilities of comparable risks.

76. Based on its proposed capital structure, Minnesota Power, through Dr. Roger A. Morin, made the following recommendations for ROR and ROE:[81]

| | Percent of Total | Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt | 45.21% | 5.68% | 2.57% |
| Common Equity | 54.79% | 11.15% | 6.11% |
| Total | 100.0% | | 8.69% |

77. The OES, through Dr. Eilon Amit, also made recommendations on both the Company's ROR and ROE:[82]

| | Percent of Total | Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt | 47.89% | 5.68% | 2.72% |
| Common Equity | 52.11% | 10.74% | 5.59% |
| Total | 100.0% | | 8.32% |

## D. The Discounted Cash Flow ("DCF") Model.

78. The DCF model is based on the theory that a stock's price represents the present value of all future expected cash flows. The DCF model is widely used to determine ROEs for

[81] MP Brief, at 67, 78. No party challenged the average cost of debt. The OES witness, Dr. Amit, agreed to a cost of debt of 5.68%. Ex. 118, Amit Direct, at 56.
[82] Ex. 121, Amit Surrebuttal, at 3.

utilities. The DCF model expresses the ROE as the sum of the expected dividend yield and long-term growth rate.[83]

79. The most common form of the DCF model is the "Constant Growth" form. Under the Constant Growth DCF model, the price of a stock is a function of the collective ROE required by investors, which is determined as the sum of dividend yield and growth.[84]

80. The Commission has relied upon the "constant-growth" form of DCF (rather than any one of several variations of the DCF method) in a number of recent rate cases. The "two growth rates" DCF (TGDCF) model that Dr. Amit principally relied on in this rate case is an extension of the constant growth rate DCF model.[85] That two-stage DCF is a reasonable method for determining ROE where the short-term projected dividend growth rates for a company may not be expected to continue in the long-run.[86]

81. TGDCF analysis uses a short term growth rate for the first five years of the period of analysis, and a long-term growth rate for years six to infinity. The long-term growth rate reflects the sustainable growth in value.[87] TGDCF assumes that for a relatively short period earnings and dividends may grow annually at a different rate than the long-term sustainable growth rate, and at the end of this short period, both earnings and dividends will grow at a constant, sustainable annual rate.[88] Use of the TGDCF is a more accurate method of determining present value when companies in the comparison group have projected short-term growth rates that are unsustainable in the long run.[89]

## E. The Company's ROE Recommendation.

### 1. Summary of the Company's ROE Recommendation.

82. Minnesota Power proposed an ROE of 11.25% based on Dr. Morin's analysis. He conducted a number of studies, relying primarily on a Constant Growth DCF analysis, which initially resulted in mean ROE figures of 10.78% and 10.82%. Dr. Morin also incorporated the results of his Capital Asset Pricing Model ("CAPM") analysis to arrive at his ROE figure.[90] MP contends that Dr. Morin's analysis corrected flaws in the various modeling approaches and accounted for a significant increase in investor risk based primarily on the Company's customer mix.

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[83] Ex. 118, Amit Direct, at 4; Ex. 119, Amit Direct Exhibits, EA-42, Appendix A.
[84] Dr. Morin described the traditional DCF model as Ke = D1/Po + g where where "k" equals the required return, "D1" is the current dividend, "g" is the expected growth rate of earnings, dividends, earnings, and book value, and "Po" represents the subject company's stock price. Ex. 14, Morin Direct, at 53.
[85] Ex. 119, Amit Direct Exhibits, (EA-42), Appendix A, p. 7.
[86] Ex. 118, Amit Direct, at 29,
[87] *Id*. at 30.
[88] *Id*. at 5.
[89] Ex. 118, Amit Direct, at 29; Tr. Vol. 6 at 116-117 (Amit).
[90] Ex. 14, Morin Direct, at 6-7.

### 2. Comparable Groups.

83. Dr. Morin examined a group of investment-grade dividend-paying utilities designated as "integrated" utilities by S&P. These companies all possess electricity generation, distribution, and transmission assets, based on Value Lines' SIC code. Dr. Morin applied screens to exclude foreign companies, private partnerships, private companies, non dividend-paying companies, companies with market capitalization of less than $500 million, and companies below investment-grade. At least 50% of the revenues of the remaining 29 companies (Integrated Electric Utility Group) came from regulated electric utility operations.[91]

84. Dr. Morin applied the DCF analysis, rather than the TGDCF analysis, to the Integrated Electric Utility Group using the growth forecast published by Value Line and arrived at an estimate of equity costs of 10.2% for the group. With recognition of flotation costs, Dr. Morin's cost of equity estimate rose to 10.4%.[92]

85. Dr. Morin did the same analysis using the consensus analysts' earnings growth forecast published by Zacks. His result was a cost of equity for the adjusted Integrated Electric Utility Group of 11.3%, unadjusted for flotation cost. Dr. Morin then added flotation costs to bring the cost of equity estimate to 11.6% under that analysis.[93]

86. Dr. Morin also applied the Value Line and Zacks forecasts to the electric utilities that make up Moody's Electric Utility Index (less one member of the Moody's Group for which no forecast was available). Those DCF analyses resulted in an estimated cost of equity of 10.9% for the Moody's Group. When he adjusted the Value Line forecast for flotation costs, the cost of equity rose to 11.1%. When he adjusted the Zacks forecast for the Moody's Group for flotation costs, the cost of equity rose to 11.0%.[94]

87. The following table summarizes Dr. Morin's ROE results for his two groups:

| **Minnesota Power ROE Comparison**[95] | |
|---|---|
| **Study Type** | Derived ROE |
| CAPM | 11.2% |

[91] Ex. 14, Morin Direct, at 60-61.
[92] Ex. 14, Morin Direct, at 61, RAM Schedule 5.
[93] Ex. 14, Morin Direct, at 62, RAM Schedule 6.
[94] Ex. 14, Morin Direct, at 62-63, RAM Schedule 7.
[95] Ex. 14, Morin Direct, at 70.

| | |
|---|---|
| Empirical CAPM | 11.5% |
| Risk Premium Electric | 10.5% |
| Allowed Risk Premium | 10.1% |
| DCF - Vertically Integrated Elec Utilities - Value Line Growth | 10.4% |
| DCF - Vertically Integrated Elec Utilities - Zacks Growth | 11.6% |
| DCF - Moody's Elec Utilities - Value Line Growth | 11.1% |
| DCF - Moody's Elec Utilities - Zacks Growth | 11.0% |

88. The mean and midpoint of Dr. Morin's analyses was 10.9%. From that number Dr. Morin added an additional 25 basis points (.25%) to the ROE figure to account for his perception of increased risk based "on utility bond yield spread differentials between A-rated and Baa-rated bonds, on observed beta differentials, and on [his] professional judgment." The resulting ROE that he proposed was 11.15%.[96] Based on his capital structure analysis, Dr. Morin proposed an overall ROR for Minnesota Power of 8.69%. **CITE**.

## F. The OES's ROE Recommendation.

### 1. Summary of the OES's ROE Recommendation.

89. The OES proposed an ROE of 10.74% based on Dr. Amit's analysis. Based on his capital structure analysis, the OES proposed an overall ROR for Minnesota Power of 8.32%.[97]

### 2. The OES's Comparable Groups.

90. Dr. Amit, testifying on behalf of the OES, prepared two comparison groups to analyze MP's ROE requirement. One group was comprised of electric companies[98] and the other comprised of electric/gas companies.[99] For the electric company group, Dr. Amit selected domestic electric utilities that: a) were listed in the Compustat database of April 2008 (provided by S&P) and b) met two conditions: their primary Standard Industrial

[96] Ex. 14, Morin Direct, at 72-73.
[97] Ex. 121, Amit Surrebuttal, at 29.
[98] Described as the Initial Electric Comparison Group ("IECG").
[99] Described as the Initial Combination Comparison Group ("ICCG").

Classification (SIC) code was 4911 (electric utilities), and their shares were publicly traded on one of the stock exchanges.[100]

91. Dr. Amit screened the electric companies that remained to eliminate those that did not have regulated retail electric services as their primary business, those lacking a bond rating, those with bond ratings outside the range BBB- to A (ALLETE's rating is BBB+), those without dividends or a reliable dividend history, those whose regulated revenues were less than 60 percent of total company revenues, and those whose beta and standard deviation varied by more than one standard deviation from the group's mean. Those screens left 21 companies that Dr. Amit identified as the Initial Electric Comparison Group ("IECG").[101]

92. Dr. Amit applied several risk measures to the IECG to assess the similarity of each company to MP. He applied a DCF analysis to each company to identify those whose ROE deviated significantly from the average required rate for the group. To address companies whose ROE was demonstrably different from MP's likely ROE, Dr. Amit applied an ROE screen. He described his rationale for that screen as follows:

> Under basic financial and economic principles, companies with similar investment risks are expected to have similar required rates of return. Therefore, after performing a DCF analysis on my IECG group, I eliminated from this group the companies with required rates of return that deviated significantly from the group's average required rate of return.[102]

93. The screen that Dr. Amit had used was "any company for which the DCF analysis resulted in a required rate of return that deviated by more than one standard deviation from the IECG's average required rate of return."[103] MP objected to this screen as having "biased the selection of comparable companies by prejudging their DCF results."[104] But the ALJ finds that criticism to be unjustified. That screen excluded companies whose rate of return is either overly high or overly low, since an unusual ROE would reflect conditions that made that company fundamentally dissimilar to MP. Fourteen companies were left after that screen was applied, and those companies were identified as the Final Electric Comparison Group (FECG). Dr. Amit applied similar screens to arrive at his Final Combination Comparison Group ("FCCG").[105]

94. Dr. Amit concluded that the companies in his comparison group required the use of TGDCF to accurately determine present value. In the recent *Otter Tail Power* rate case

[100] Ex. 118, Amit Direct, at 7-9.
[101] Ex. 118, Amit Direct, at 7-9.
[102] Ex. 118, Amit Direct, at 25.
[103] Ex. 118, Amit Direct, at 26.
[104] MP Brief, at 70.
[105] Ex. 118, Amit Direct, at 14-15.

proceeding, the Commission accepted both the OES's use of the TGDCF method and the results the OES obtained.[106] Applying that analysis to his two comparison groups in this proceeding, Dr. Amit arrived at the following ranges of ROEs:[107]

| | DCF/TGDCF | | | |
|---|---|---|---|---|
| | Low | Average | High | CAPM |
| FECG | 10.00% | 10.77% | 11.53% | 10.09% |
| | [4]9.97% | [4]10.74% | [4]11.51% | |
| FCCG | 9.34% | 10.41% | 11.48% | 10.35% |

95. The ALJ finds that Dr. Amit's comparable groups are appropriate for use in calculation of an ROE for Minnesota Power. By contrast, the ALJ finds that Dr. Morin's comparable groups were not closely tailored to match MP's financial profile. Dr. Amit's approach to comparable groups is also consistent with the Commission's longstanding approach to calculating ROE.

**G. Impact of Risk on ROE.**

96. Although Dr. Morin's and Dr. Amit's ROE analyses differ in a number of particulars, Dr. Morin considered that most of those differences were "minor" and that the only thing about which they fundamentally disagreed was that Dr. Morin "added an additional risk premium" to his estimated ROE "in order to recognize MP's peculiar risk circumstances."[108] One of the major issues in setting an appropriate ROE is therefore whether or not an additional risk premium is warranted.

97. The DCF model is based on *long-term* growth and assumes cash flows in perpetuity and a constant dividend payout ratio. Dr. Amit addressed the constant growth bias in the DCF model by using the TGDCF approach. But Dr. Morin maintained that the DCF model would undervalue ROE requirements because "we have entered an era where investors are repricing risk. We are witnessing a fundamental shift in risk aversion on the part of investors."[109]

98. Minnesota Power argues that its risks are higher than the normal electric utility for several reasons. One risk that Dr. Morin identified was the Company's reliance on sales to a few extremely large industrial customers concentrated in the volatile taconite and paper industries. He also believed that Minnesota Power's planned construction program magnified that risk. Finally, Dr. Morin also identified MP's reliance on coal-based

[106] *Otter Tail Power 2008 Order*, at 58.
[107] Ex. 118, Amit Direct, at 46, Table 10. The middle row of ROE's was determined using FECG's average growth rate as the second period growth rate in the TGDCF analysis. *Id*.
[108] Tr. Vol. 1, at 150-151 (Morin).
[109] Tr. Vol. 1, at 153 (Morin).

generation as another risk factor because of uncertainty about the potential for future regulations to reduce greenhouse gas emissions.[110]

99. Minnesota Power also relied the fact that in its 1994 ratemaking proceeding, the Commission had expressly adjusted for MP's unusual risk factors.[111] But Dr. Morin acknowledged that the increase in the Company's equity ratio from its 1994 capital structure significantly mitigated the risk that may have existed in 1994.[112] Dr. Morin compared the beta of ALLETE to that of the companies in Dr. Amit's comparison groups. Dr. Morin maintained that he adjusted those betas for capital structure differences, to "purge" the financial risk from total risk and found that Minnesota Power's unlevered beta (which reflects business risk only) remained considerably higher than the average of Dr. Amit's comparison groups.[113]

100. Beta is basically a measure of the volatility of a stock relative to the volatility of the market as a whole.[114] Dr. Amit compared the volatility of returns of MP and ALLETE and found that ALLETE volatility was much higher than MP. On the other hand, Dr. Morin's analysis does not incorporate that step. Rather, Dr. Morin concludes, in substance, that since ALLETE is riskier than a typical utility electric utility, then it follows that MP is riskier. In other words, Dr. Amit disagreed with Dr. Morin's failure to isolate MP's risk from ALLETE's in his calculations.[115] Moreover, Dr. Amit used, as a reasonable measure of volatility, the standard deviation of revenues and rates of return to substitute for beta (which MP lacks). He made that calculation with an adjustment for differences in annual revenue between ALLETE, MP, the FECG, and the FCCG. That comparison indicated that MP is less risky than both comparison groups that Dr. Amit used.[116] Dr. Amit also noted that ALLETE's BBB+ bond rating (itself a measure of risk) is higher than that of any company in the FECG. This necessarily means that MP has less risk than any of the FECG companies.[117]

101. Dr. Morin identified concentration of large customers as another reason to adjust MP's ROE to account for greater risk. On the other hand, Dr. Amit noted that Minnesota Power's cost of electricity is among the lowest in the country.[118] He concluded that the loss of any particular customer load would result in MP having more power to sell on the Midwest Independent System Operator (MISO) Day 2 market, which did not exist at the time of the Commission's 1994 MP Order. With an available market for MP's excess low-cost

[110] Ex. 15, Morin Rebuttal, at 3-4.
[111] MP Brief, at 67.
[112] Tr. Vol. 1, at 151 (Morin).
[113] Ex. 14, Morin Direct, at 6, Sched. RAM-1; Ex. 15, Morin Rebuttal, at 5; Ex. 16, Morin Rebuttal Exhibit.
[114] Tr. Vol. 6, at 141 (Amit).
[115] Tr. Vol. 6, at 142-144 (Amit).
[116] Ex. 121, Amit Surrebuttal, at 8-10.
[117] *Id*. at 8.
[118] Amit Surrebuttal, at. 7.

power, the potential for loss of a large customer due to economic conditions does not constitute a basis for increasing MP's ROE.[119]

102. The ALJ concludes Dr. Amit's DCF analysis accounts for an appropriate level of any risk posed by MP's customer mix and other potential risk factors, particularly since the Company has the option of selling available power through MISO. The ALJ also concludes that Dr. Morin's adjustment for risk unreasonably emphasizes investor risk in his ROE calculation.

### H. Flotation Cost Adjustment.

103. Dr. Morin indicated that when a company issues additional shares of common stock, the increased supply of common stock normally causes a downward pressure on the price per share, and that based on various academic studies, a reasonable measure of the relative price decline is about 1.5 percent. Dr. Morin therefore maintained that an additional 1.5 percent in flotation cost adjustments should be made to address that reduction in price.[120]

104. Dr. Amit disagreed with Dr. Morin's additional flotation cost adjustment of 1.5 percent. While Dr. Amit acknowledged that numerous financial studies indicate that market pressure costs may generally exist when additional shares of common stocks are being issued, those market pressure costs vary across companies and across market conditions. Dr. Amit concluded that an adjustment to the flotation costs to reflect market pressure for Minnesota Power "is warranted only if MP shows that such costs have existed for its public issuances."[121]

105. Minnesota Power did not offer any empirical data to support that issuing new shares of ALLETE stock has created the downward pressure on the price per share described by Dr. Morin. Dr. Amit analyzed ALLETE's price behavior in comparison with the Dow Jones' price behavior for 30 days prior to ALLETE's public issues in 1993, 1998, and 2001. On the days of ALLETE's public issues, its stock price went down by less than the closing price of the Dow Jones. From that, Dr. Amit concluded that there is no market pressure impact on ALLETE (and therefore on Minnesota Power). Dr. Amit also observed that the average price of ALLETE stock declined by only an average of 0.15 percent during the 30 days prior to ALLETE's previous three stock issues. Based on that data, Dr. Amit concluded that no market pressure adjustment to flotation costs is warranted for Minnesota Power because historically no significant market pressure on ALLETE's stock price has been observed.[122]

[119] Ex. 118, Amit Direct, at 74-75; Ex. 121, Amit Surrebuttal, at 36-37.
[120] Ex. 14, Morin Direct, at 66-69; Ex. 15, Morin Rebuttal, at 8.
[121] Ex. 121, Amit Surrebuttal, at 10-11.
[122] Ex. 121, Amit Surrebuttal, at 11-12, Attachment No. (EA-S-4).

106. In calculating flotation costs, Dr. Morin relied on empirical studies of several different companies' stock issues in the range of $60 to $500 million that had shown the average direct flotation costs for stock issues in that range to be between 3.5 percent to 5 percent. It was also Dr. Morin's opinion that allowing for market pressure costs, as described above, raises the flotation cost allowance to well above 5%.[123] On that basis, Dr. Morin used a 5 percent flotation cost figure.

107. While the OES agreed with much of MP's DCF methodology, the OES contends that the flotation costs that the Company used were too high. Dr. Amit based his analysis on his conclusion that the correct flotation costs were those associated with the historical issuance costs for ALLETE, which averaged 3.61 percent. Using ALLETE's costs in Dr. Amit's ROE calculation resulted in a reduction of seven basis points from the results obtained by Dr. Morin for ROE.[124] The ALJ concludes that Dr. Amit's approach to calculating flotation costs is more reasonable and reliable than Dr. Morin's and further supports the OES ROE result for calculating Minnesota Power's revenue requirements.

**I. Dividend Yields.**

108. An important part of the DCF analysis is determining an appropriate dividend yield. Dr. Morin and Dr. Amit differed in their respective approaches to calculating dividend yield. Dr. Morin argues that Dr. Amit's approach understates the proper dividend yield,[125] while Dr. Amit argues that Dr. Morin's approach overstates dividend yield. Both economists agree that the annual DCF model states that the expected dividend to be used is $D_o$ (1+g), where $D_o$ is the current annual dividend rate and g is the annual expected growth rate, and that expected dividend assumes that $D_o$, the annual dividend rate at the time the DCF is performed, would increase by g a year from the date at which the DCF was performed.[126]

109. Dr. Morin maintains that the normal methodology of the annual DCF model should be employed, that the appropriate expected dividend to be used in that analysis is the current dividend times (1 + expected growth rate)[which is ($D_o$ (1+g)], and used an example with the result is 4%(1 + .06) = 5.24 percent (differing from the results of Dr. Amit's method by 12 basis points).[127]

110. On the other hand, Dr. Amit maintained that the appropriate dividend calculation would use one-half of the expected growth rate ($D_o$ (1+g/2)). It is his opinion that the timing of dividend payments results in an overstatement of expected dividend yield using the $D_o$

[123] Ex. 14, Morin Direct, Schedule 10 at 1-3.
[124] Ex. 118, Amit Direct, at 58-59.
[125] Ex. 15, Morin Rebuttal, at 12.
[126] Ex. 15, Morin Rebuttal, at 12-13; Ex. 121, Amit Surrebuttal, at 17.
[127] Ex. 15, Morin Rebuttal, at 13.

(1+g) formula as proposed by Dr. Morin, and that overstatement translates into a higher ROE award than is warranted by the actual financial results forecast by the DCF model.[128]

111. Dr. Amit reasons that conceptually the appropriate dividend to be used in the DCF analysis may be the annual dividend rate at the beginning of the next period (year). However he argues that if all the companies in his group were to increase their dividend in the second quarter of 2008, the appropriate dividend rate to be used in the DCF analysis would be the annualized dividend based on the second quarter of 2008, increased by the growth rate, "g." But the companies in his group might raise their dividend rates in different quarters. Moreover, for some of those companies the current dividend rate might not change over the next one or two quarters but then increase in subsequent quarters. For other companies, the dividend yield may remain constant for three or four quarters. Thus, in Dr. Amit's opinion, a reasonable estimate of the expected annual dividend yield for the IECG can be derived as the most current annualized dividend yield x (1 + 0.5g), where "g" is the expected growth rate.[129]

112. The ALJ concludes that Dr. Amit's more nuanced approach to dividend yield is a more accurate estimation of the Company's dividend yield and that use of the formula that Dr. Amit proposes for estimating expected dividend—i.e., the $D_o$ (1+g/2) formula —is therefore appropriate.

## J. Updating of Stock Price Data.

113. In his initial DCF study, Dr. Amit calculated the dividend yield by using thirty-day average closing stock prices for his comparison groups from the period May 8 through June 9, 2008.[130] Dr. Amit emphasized the importance of using the most current price per share because it "incorporates all publicly available information." He also stated that "non-recent historical prices should be avoided in calculating the dividend yield."[131] Dr. Morin testified that the DCF analysis that Dr. Amit employed generally presents difficulties because utility company historical data have become less meaningful for an industry in a "state of change" and past earnings and dividend trends are not necessarily indicative of the future earnings.[132] It is in the context of that belief that the Company argues that Dr. Amit's failure to update the prices of the stocks he relied on in his surrebuttal testimony is fatal to his DCF results and results in artificially low dividend yields, which are completely unrealistic in today's markets.[133]

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[128] Ex. 121, Amit Surrebuttal, at 16-18.
[129] Ex. 121, Amit Surrebuttal, at 16-18.
[130] Ex. 118, Amit Direct, at 20.
[131] *Id*. at 19.
[132] Ex.14, Morin Direct, at 20.
[133] MP Brief, at 74-75.

114. In response, Dr. Amit acknowledged that his uniform practice in other rate cases has been to update his dividend yield analysis with his surrebuttal testimony, but in this case he declined to do so because of the abnormal conditions in equity markets that have prevailed since June 9, 2008.[134] It is Dr. Amit's opinion that although stocks of utilities are less sensitive to market volatility, they are not immune from that volatility, and that rather than using data on dividend yield from a period when markets are volatile, it is more prudent to rely on an historical period for data.[135]

115. In Dr. Amit's opinion, the unpredictable ways in which market conditions have moved are not likely to continue throughout the test year (and even less likely to last through the effective life of the rates set in this proceeding).[136] As Dr. Amit also noted, the federal government has taken action toward adopting direct stimulus spending of over $700 billion to address the current conditions in the national economy.[137] In this proceeding, Minnesota Power has not shown that the recent market volatility is likely to continue over the long term or shown what particular data would more accurately reflect future market conditions. One can only speculate about the data in a fluctuating market that might correctly predict the direction of the market when the dramatic swings stop. When balancing the interests of shareholders and ratepayers, the burden is on MP to demonstrate that its ROE proposal results on just and reasonable rates. In this instance, using the stable market information of the recent past is superior to relying more recent data in a highly volatile market. The ALJ therefore concludes that Dr. Amit's conclusion concerning a just and reasonable ROE is not less reliable because it is not based on updated market information.

## K. ROE and ROR Conclusions.

116. The OES proposals for capital structure, ROE and ROR are fair and reasonable and should be adopted:

| | Percent of Total | Cost | Weighted Cost |
|---|---|---|---|
| Long Term Debt | 47.89% | 5.68% | 2.72% |
| Common Equity | 52.11% | 10.74% | 5.59% |
| Total | 100.0% | | 8.31% |

[134] Tr. Vol. 6, at 122-127 (Amit).
[135] *Id*. at 125.
[136] Tr. Vol. 6, at 124 (Amit).
[137] Ex. 121, Amit Surrebuttal, at 2.

## IV. WHOLESALE MARGINS.

117. The following treatment of wholesale margins for rate making purposes is divided into three subject areas: asset-based margins, non-asset-based margins, and ancillary service market ("ASM"). Each of those areas raised issues that will be addressed separately.

### A. Asset-Based Margins.

118. Asset-based margins result from the Company's sale of energy generated by its own facilities that is not needed to serve its retail needs. The cost of assets used to generate the energy sold into the market must be included in rates, since ratepayers are incurring the cost of the assets generating those margins. The principle is well-accepted that treatment of asset-based margins must benefit the ratepayers.[138]

119. MP maintains a total of 1,408 MW generating capacity; 1,246 MW of the total is coal-fired. The remainder is a mix of purchased steam, biomass, and hydro-generated electricity.[139] Minnesota Power described how it now sells energy it generates in the wholesale market:

> Minnesota Power's participation in the wholesale electric market changed significantly on April 1, 2005, with the beginning of the MISO Day 2 Energy Market. While Minnesota Power's customers still receive the benefit of the Company's low-cost generation, the methods used to allocate the costs of energy within the MISO footprint are now significantly different. Prior to the MISO Day 2 Market, Minnesota Power generated energy to serve its retail load, selling any excess energy to wholesale energy purchasers directly or through traders, and buying any energy shortfall it experienced from wholesale energy sellers directly or through traders. After the advent of MISO Day 2, however, Minnesota Power and all other generators must offer all the energy they generate into the Day 2 Market for sale, and must purchase all of the energy needed to serve its retail load out of the Day 2 Market. This market structure is intended to allow more efficient and effective use of generation and transmission resources, and eliminate the higher, and hidden, costs associated with discriminatory and self-dealing energy transactions.[140]

#### 1. Asset-Based Margin Forecast.

120. In its initial filing, Minnesota Power forecast Minnesota jurisdictional asset-based wholesale margins of $22 million for the test year. That amounted to a significant reduction from

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[138] *Otter Tail Power 2008 Order*, at 23.
[139] Ex. 27, Norberg Direct, at 5.
[140] Ex. 33, Seeling Direct, at 5.

its historical asset-based sales figures. The Company maintained that the reduction was supported by the expiration of long-term wholesale contracts with three utilities - Alliant, SMMPA, and GenSys – contracts that have not been renewed.[141] The Company asserted that those contracts represented a total of 155-170 MW of energy that the Company will no longer be selling at wholesale.[142] The Company also indicated that:

> Minnesota Power's customer requirements are projected to continue to expand. In addition to continued commercial and residential growth, about 100 MW in industrial expansions is forecast to occur. A key resource "addition" will be the termination of a 175 MW off-system sale to GRE (see Table on page 6 of this testimony) in April 2010; Taconite Harbor Energy Center will then be available for Minnesota Power retail service.[143]

121. The OES objected to the Company's $22 million forecast as too low. It based its objection on the fact that the energy for those wholesale contracts came from Minnesota Power's Boswell and Taconite Harbor generation units, and that Minnesota Power therefore still has the low-cost power from those plants available to continue selling at wholesale to other utilities and energy purchasers through bilateral contracts or the MISO Day 2 wholesale energy market.[144]

122. Minnesota Power indicates that it executed the SMMPA and GenSys contracts when its purchase of the Taconite Harbor generating station provided it with excess generation. It then obtained Commission approval to move Taconite Harbor from non-regulated to rate-based generation with the understanding that the SMMPA and GenSys wholesale contracts would continue. The Commission's approval contemplated that generation from Taconite Harbor would be available for retail load subject to those pre-existing wholesale contracts.[145] Although the SMMPA and GenSys contracts have expired, the Company indicates that the energy produced by Taconite Harbor is now used to meet the supply requirements of a 175 MW wholesale contract with Great River Energy and therefore is not available for more wholesale, or retail, sales.[146]

123. Minnesota Power further indicates that it entered into the SMMPA and GenSys contracts sales during times of extended industrial downturns that made it prudent to sell power at wholesale to offset retail customer revenue requirements as much as possible. The

[141] Ex. 27, Norberg Direct, at 6.
[142] *Id*.
[143] Ex. 27, Norberg Direct, at 7.
[144] Ex. 95A, Campbell Direct, at 20-21.
[145] MP Brief, at 34, footnote 5 (citing *ITMO the Minnesota Power 2004 Integrated Resource Plan*, Docket No. E-015/RP-04-865, Paragraph 1.3.A (Commission Order Accepting Resource Plan, Accepting Settlement as Amended issued October 27, 2005) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3085521).
[146] Ex. 27, Norberg Direct, at 6; Tr. Vol. 5, at 151-152 (Campbell).

Company asserts that when the regional economy and Minnesota Power's industrial customers experienced a dramatic recovery and expansion beginning in 2004-05, the energy requirements to serve the Company's customers also increased significantly. When those committed off-system sales ended in late 2007/early 2008, Minnesota Power was routinely purchasing 100-150 MW of energy on a daily basis through both bilateral and MIS0 Day 2 market transactions to meet its retail customers' needs. With off-system sales ended, the Company contends that those 100-150 MW of purchased energy are now used to meet retail demand. Minnesota Power argues that this increased use of self-generation for retail reduces the need for Minnesota Power to access the energy markets for system needs, lowering costs for ratepayers.[147]

124. Additionally, the Company asserts that, of the energy market purchases it had been making, it needed 75 MW to replace the 75 MW capacity of the Company's Boswell 1 and 2 units that had been dedicated to meet the supply requirements under the Alliant wholesale contract.[148] MP also indicates that it needed the balance of the purchased power to meet a portion of the requirements of the SMMPA and GenSys wholesale contracts, as well as the Company's retail load demands.[149]

125. In addition to its existing generating capacity, MP has also identified a number of renewable sources of electricity generation that are expected to be available by 2010. To support those generation sources, MP plans to add a 170 MW peaking plant powered by natural gas. These resources are intended to help MP meet its statutory obligation to increase its renewable generation sources.[150] MP is required to provide 25 percent of its total retail electric sales to retail customers in Minnesota generated through eligible energy technologies.[151]

126. Minnesota Power contends that under "relevant statutes, Commission orders, and prudent utility practices" the Company is required to dispatch its generation on an economic basis that serves native load first.[152] Minnesota Power maintains that this obligation is met by "stacking" its generation from the lowest cost to the highest cost, using the lowest cost available sources from the stack first to serve retail customers.[153] MP has not explained how its practice is consistent with the 25% renewable requirement which is in place now with lower compliance levels.

127. Minnesota Power presented retail sales forecasts that were, in some cases, significantly lower than historical customer usage in 2007. The ALJ has recommended that the

[147] Ex. 29, Norberg Rebuttal, at 13.
[148] Tr. Vol 2, at 209-10 (Seeling).
[149] *Id*. at 211.
[150] Ex. 27, Norberg Direct, at 8.
[151] Minn. Stat. § 216B.1691, subd. 2a (a).
[152] Ex. 29, Norberg Rebuttal, at 14.
[153] *Id*.

Commission accept the OES's higher forecasts for residential and general service classes[154] and, with one significant exception, the OES's recommendation for somewhat higher forecasts for Large Light and Power customers.[155] But the ALJ agreed with the Company's forecast for lower test year usage by Large Power customers than what those customers used in 2007.[156] As previously noted, the Company's large power customers have accounted for as much as 70 percent of its retail sales,[157] and it was extended industrial downturns and resultant usage reductions by those customers that prompted the company to enter into the power purchase agreements which are now expiring. In other words, Minnesota Power has not identified any retail customer sales growth that would preclude energy from its expiring wholesale contracts from being sold in other wholesale transactions that will generate significant asset-based margins consistent with MP's historical sales.

128. The ALJ therefore concludes that it is unlikely that the Company will need all of the power made available by the expiration of the SMMPA and GenSys contracts to serve its retail customers. Minnesota Power has not identified any basis for its lower forecast of asset-based margins beyond the possibility that the three identified wholesale contracts might not be renewed. This contrasts sharply with the consistent history of MP's asset-based margins since the MISO Day 2 market began operation.[158] The ALJ therefore concludes that Minnesota Power's asset-based margin forecast is too low, and that the Commission should accept the OES's test year estimate of asset-based margins.

### 2. The OES's Approach to Calculating a Fixed Credit for Asset-Based Margins.

129. The OES has proposed calculating a fixed credit for asset-based margins to be applied through base rates. To calculate the credit, the OES recommends using the Company's average actual asset-based margins, within the Minnesota Jurisdiction, from 2005 through 2007. During that period, Minnesota Power realized positive margins of $20,529,898, $42,609,138 and $41,736,879, respectively, using Minnesota Jurisdictional amounts. The resulting average would therefore be $34,958,638.[159]

130. Both the OES and MP have proposed that the fixed credits be recognized through base rates. MCC proposed that a fixed credit to base rates not be used, suggesting instead that these margins could be passed to rate payers through the fuel clause adjustment (FCA). MCC maintains that this approach addresses variablity in the amounts of these margins and directly credits customers based on actual use of electricity, thereby

[154] *See* Finding 48.
[155] *See* Finding 55.
[156] *See* Findings 59-61.
[157] *See* Finding 41.
[158] Ex. 95A, Campbell Direct, at 19.
[159] Ex. 96, Campbell Surrebuttal, at 18 and NAC-6.

eliminating cross-class subsidies.[160] However, Minnesota Power contends that this approach would be inconsistent with the Company's current practice, which the Commission has already approved. The Company notes that if the Commission were to adopt the FCA credit proposal, then an exception would be necessary to address a loss of load, and the details of that exception would require further development.[161] As the Commission recently held, "In sum, the Commission will set Otter Tail's base rates on the assumption that Otter Tail's costs are offset by $5.41 million in revenues from Otter Tail's asset-based wholesale margins."[162] The ALJ concludes that recognizing the credit through base rates is appropriate.

131. The OES acknowledged that adoption of the $34,958,638 three-year average, less the $22,057,477 amount MP proposed in its test year, would result in a $12,901,161 adjustment,[163] and it offered the following justification for such an adjustment:

- Using a historical average of past asset-based margins is a reasonable and fair way to estimate asset-based margins for purposes of developing reasonable rates.

- In OTP's recent rate case the Commission approved a four year average of asset-based margins. For MP, the OES considers a three year average to be more reasonable largely to insure a representative amount of asset-based margins is included in the test-year. Also due to the discretion MP had, and OTP did not have, in deciding when to file its rate case. The Commission required OTP to file a rate case by October, 2007, whereas MP had a choice regarding when to file its rate case.

- In assessing the effects of MP's additional flexibility in deciding when to file its rate case on its proposed costs and revenues in this rate case, the OES notes that MP chose a forecasted test year which appears to be designed to minimize MP's expected revenues and thus result in higher rate increases. For example, some of MP's wholesale contracts have recently expired at the end of 2007 and early in 2008, however as noted above those revenues from MP's generators will still be available to MP through new sales. In addition, as shown on MP's Schedule A-3, page 1 of 2, Other Operating Revenue, which went from $116 million in 2007 based on actual information to $74 million in the test year. By contrast, OTP used a historical test year in its most

[160] Ex. 74, Blazar Direct, at 5-6.
[161] Ex. 28, Norberg Rebuttal, at 15-16.
[162] *Otter Tail Power 2008 Order*, at 26.
[163] Ex. 96, Campbell Surrebuttal, at 18 and NAC-6.

recent rate case. Thus, the Commission needs to ensure that MP's ratepayers are not prejudiced by MP's choice of a test year, and ensure that the test year amount of asset-based margins is a reasonable representative amount.

- The Commission noted in the OTP rate case that there should be less reliance on pre-MISO Day 2 asset-based margins. OES has noted in the Annual Automatic Adjustment Reports (AAA Reports or Annual Electric Fuel Reports) that asset-based margins increased with the start of the MISO Day 2 market. OES has also noted in the most recent Xcel rate case, in the most recent OTP rate case and in the current MP rate case that asset-based margins clearly increased after the start of the MISO Day 2 market in April 2005

- One of the benefits of the MISO Day 2 market is the efficient sale of excess generation not needed for retail into the MISO Day 2 market. Since ratepayers are paying for all of the administrative and other costs of the MISO Day 2 market, they should also be given a reasonable level of the benefits for the sale of excess generation.[164]

132. The ALJ concludes that using a three-year average of actual asset-based margins is the most reasonable approach for determining a representative level of asset-based margins in the test year setting the Company's rates. Moreover, selecting 2005, 2006, and 2007, as the period for averaging historical asset-based margins is a reasonable and appropriate method for determining asset-based margins for the test year. By contrast, Minnesota Power's test year forecast is $6 million below the actual margins for the last full year for which data is available. In summary, the OES approach to forecasting asset-based margins for the test year is reasonable and results in an appropriate level of forecast revenue to apply as a fixed credit to be applied to base rates.

## B. Non-Asset-Based Margins.

133. Non-asset-based margins result from the unregulated purchase and sale of energy for non-retail purposes. Typically, the same utility marketers, sharing common equipment, handle both asset-based margins and non-asset-based purchase and sale transactions. The Commission requires some attribution of wholesale non-asset-based margins to ratepayers to the extent that ratepayers funded services allowed the utility to receive

[164] Ex. 95A, Campbell Direct, at 21-23.

those wholesale margins.[165] It is therefore appropriate for non-asset-based margins to cover their incremental costs and provide a reasonable contribution towards common costs. However, Minnesota Power is not performing non-asset-based trading transactions except for limited virtual transactions to hedge prices between Day-Ahead and Real-Time markets on behalf of retail customers.[166] In other words, the Company's only participation in those markets is to ensure that it can provide least-cost supply to its customers. Where those purchases exceed requirements, the excess is sold to the market and the margins obtained are allocated to the FAC.[167]

134. Nonetheless, the OES proposes that a $300,000 cap on ratepayer responsibility be imposed on any net losses that might arise from those virtual transactions.[168] Because the Company reported net losses of $160,000 from virtual transactions in its FYE 2007 Annual Automatic Adjustment report, the OES believes that imposition of a $300,000 cap would function as a protective measure to ensure that MP's cost of hedging does not become too high.[169] The proposed cap would apply to net losses arising from hedging transactions over a one-year period. Any losses in excess of the cap would not be allowed for recovery via the FCA. Therefore, any losses in excess of the cap would be incurred by the Company's shareholders. The OES also recommends that language specifying that no costs from speculative trading will be allowed in the FCA or otherwise be charged to ratepayers be incorporated in the Company's rates tariff to ensure that its future virtual trading will never be speculative.[170]

135. Minnesota Power opposes the proposed cap, arguing that it could possibly impede transactions that are beneficial to ratepayers.[171] Where energy is sold in day-ahead virtual transactions and purchased back in real time, a margin is created. In the Company's experience, the real-time market is lower priced than the day-ahead market more than 50% of the time, and therefore most of the time the margin created is positive. The Company indicates that it only uses virtual transactions in the MISO Day 2 energy market on a limited basis and these transactions are a very effective way to move energy from the day-ahead market to the real-time market (or vice versa) to minimize ratepayer costs.[172] Minnesota Power treats the margins from virtual transactions in the same manner it treats margins created by excess purchases, that is, all margins plus or minus are allocated on an energy (MWh) basis to all sales. Because of the opportunity

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[165] *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-07-1178, *Order on Reconsideration* at 3-7 (Oct. 31, 2008) https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5597314.

[166] Ex. 33, Seeling Direct at 20; Ex. 95A, Campbell Direct, at 25-26; Ex. 96, Campbell Surrebuttal, at 18-19.

[167] Ex. 33, Seeling Direct, at 20.

[168] Ex. 96, Campbell Surrebuttal, at 19-20.

[169] Ex. 95A, Campbell Direct at 27; Ex. 96, Campbell Surrebuttal, at 19.

[170] Ex. 96, Campbell Surrebuttal, at 20.

[171] Ex. 29, Norberg Surrebuttal, at 15.

[172] Ex. 95A, Campbell Direct, at 25.

to generate positive margins from prudent virtual transactions, Minnesota Power argues that its continued use should not be limited.[173]

136. The ALJ concludes that a cap on losses from the Company's virtual transactions is a reasonable measure to prevent ratepayers from having unlimited exposure to such losses, and that the proposed $300,000 cap, which is nearly twice the amount of the Company's documented historical losses, provides the Company with ample room to engage in transactions that are beneficial to ratepayers. The ALJ also concludes that tariff language specifying that no costs from speculative trading will be allowed in the FCA or otherwise be charged to ratepayers is a reasonable measure to prevent any future speculative trading.

## C. Ancillary Service Market Margins.

137. Both Minnesota Power and the OES noted that MISO expects to open a new market, called the Ancillary Services Market ("ASM"). Ancillary services "help ensure that there is sufficient generation to match loads on the transmission system instantaneously to preserve service reliability." The ASM market is intended to assist utilities to respond quickly to system fluctuations in output as well as load by providing generation assets. 174

138. ASM margins include margins from spinning reserves, regulation reserves and supplemental reserve requirements. MP described its expected involvement with ASM margins as follows:

> Minnesota Power will be participating in a joint filing to address ASM in early May. With the start of the ASM, Minnesota utilities will be able to offer energy and ancillary products in the marketplace. These products will be cleared by MISO on a co-optimized basis. MISO will economically dispatch generating units to ensure that the lowest costs of energy and ASM products are cleared. Because the ASM clearing and energy clearing are tied (co-optimized), the clearing of the ASM products will impact energy clearing. Minnesota Power will have to create, with Commission approval, the accounting mechanism necessary to ensure that ancillary services costs and revenues flow to ratepayers so that ancillary services under the ASM are aligned with the historic provision of such services. The proper treatment of ASM charges will ensure that ratepayers fully realize the financial benefits of the ASM market. Minnesota Power is presently proposing to allocate all ASM charges and

[173] MP Brief, at 37-38.
[174] Ex. 95A, Campbell Direct, at 51-52.

credits through the FAC. However, Minnesota Power has not addressed ASM implementation in its test year expenses and revenues.[175]

139. Because ASM has not begun operationally and because the ASM proceeding is currently before the Commission,[176] the OES recommends that the issues raised in the *ASM Docket* should be addressed in that separate docket before developing an ASM margin sharing proposal for Minnesota Power. In that regard, the OES recommends that the Commission expressly state in its final decision in this rate case that the Company's rates may be revised in the future to address the Company's ASM costs and revenues.[177]

140. Since Minnesota Power has not addressed the ASM issue in this proceeding, the ALJ recommends that the Commission adopt the OES's ASM recommendations.[178]

**D. $SO_2$ and $NO_x$ Allowances.**

141. Following the enactment of the 1990 Clean Air Act Amendments of 1990 (CAA),[179] the U.S Environmental Protection Agency (EPA) adopted both the Federal Clean Air Interstate Rule (CAIR),[180] requiring $SO_2$ and $NO_x$ reductions, and the Clean Air Mercury Rule (CAMR),[181] requiring reduction of mercury emissions. Under CAIR and CAMR, Minnesota developed a State Implementation Plan (SIP), which spelled out the emission allocation regime and identified the activities available for achieving rule compliance. Those activities include trading emissions allowances.

142. Minnesota Power's plans for trading emissions allowances are:

> Minnesota Power's $SO_2$ allowance allocations from the EPA are expected to exceed actual emissions through 2015, creating a surplus of allowances that could be sold to market or carried forward to future years to the benefit of ratepayers. The Company's emission allowance strategy will seek to maximize the value of its $SO_2$ credit inventory on behalf of ratepayers. In contrast, the Company expects its annual $NO_x$ emissions to exceed the annual EPA allocation in the same timeframe, creating annual deficits. The Company will seek to minimize the compliance costs associated with the projected $NO_x$ deficits by continuing to evaluate the

[175] Ex. 33, Seeling Direct, at 21.
[176] *ITMO Interstate Power and Light Company - Electric, Minnesota Power, Northern States Power Company d/b/a Xcel Energy and Otter Tail Power Company Accounting Revision to Riders for FCA to Recover Costs and Revenue Related to MISO*, Docket No. E999/M-08-528 (*ASM Docket*).
[177] Ex. 95A, Campbell Direct, at 54-55.
[178] Ex. 96, Campbell Surrebuttal, at 38-39.
[179] 42 USC § 7401, et seq. (CAA).
[180] 70 Fed.Reg. at 25,165.
[181] 42 C.F.R. Parts 60, 63, 72, and 75.

addition of emission reduction equipment to Minnesota Power's system, by strategically purchasing allowances from the market, and by maximizing the value returned to ratepayers for other emission credits such as $SO_2$.[182]

143. $SO_2$ allowances produce two potential revenue streams for the Company. First, there can be proceeds from the EPA when it withholds allowances from utilities and sells those allowances in the market. Second, a utility like Minnesota Power can sell some of its allowances either directly or through a broker. Minnesota Power projected $2,695,000 in test-year revenues from anticipated sales of surplus $SO_2$ emission allowances. That amount represented half of the projected 2009 sales of $5,195,000. The Company indicated that it did not include any budgeted revenues for the first six months of the test year because it did not plan to sell any surplus allowances in 2008.[183] Of the total projected figure, $195,000 of the budgeted amount represented anticipated proceeds from the EPA, and the remaining projection represented potential direct sales.[184]

144. Since 1994, Minnesota Power has received $4,033,237 from surplus $SO_2$ allowance sales, but none of these revenues have been applied to benefit ratepayers.[185] In this proceeding, Minnesota Power proposes to eliminate all revenues and expenses associated with its $SO_2$ and $NO_x$ allowances from the test-year but to include them in a future separate cost recovery rider.[186] The Company maintains that the market for allowances is volatile, and that allowance prices have been fluctuating significantly, making establishing the proper amount of test year revenues difficult.[187] The Company argues that those difficulties are obviated if revenues and expenses simply flow to ratepayers when incurred. MP therefore proposes to address $SO_2$ allowance revenues and expenses through a rider, rather than through base rates, and it filed a proposed rider with its initial Petition.[188]

145. The OES argues that over the last fourteen years, the Company has been predictably receiving some net revenues from the EPA's sales of its $SO_2$ allowances.[189] The OES considers the $195,000 that the Company expects to receive from the EPA in 2009 to be representative of that annual component of the Company's allowance income stream; it therefore recommends a test-year adjustment increasing MP's test-year revenues by $195,000, or $165,538 on a Minnesota jurisdictional basis. On the other hand, unlike the EPA sales, allowances that the Company sells through brokers are made at the discretion of the Company's management. Therefore, the OES believes that the

[182] Ex. 43, Hodnick Direct, at 11-12.
[183] Ex. 87A, Johnson Direct, at 27-28.
[184] *Id*.
[185] Ex. 87A, Johnson Direct, Attachment MAJ-15.
[186] Ex. 43, Hodnik Direct, at 14-15, Ex. 50, Podratz Direct, at 14-17.
[187] Tr. Vol. 3 at 44-45 (Hodnik).
[188] *See* Ex. 2, Sect. V at 87 ("Rider for Allowances and Credit Purchases/Sales").
[189] Ex. 87A, Johnson Direct, at 30.

remaining amount budgeted for the test year may not be representative of future annual proceeds from brokerage sales. Actual revenues may be higher or lower depending upon market conditions and the timing of these sales. As a result, the OES does not oppose MP's proposal to exclude these revenues from the rate case but recommends that the Commission require MP to return the revenues to ratepayers through an existing cost recovery rider.

146. The ALJ concludes that the OES proposal is a reasonable approach to ensuring that ratepayers receive the benefit of revenues the Company obtains from sales of its $SO_2$ allowances—that is, revenues and expenses that are reasonably predictable are given rate base treatment, while revenues and expenses that are likely to be volatile are covered in a rider. The ALJ expresses no opinion on whether the Commission should address allowance brokerage sales in an existing rider or in a new one.

## V. MISO ISSUES.

147. The Midwest Independent System Operator ("MISO") is a regional transmission organization (RTO). The Commission has described the duties of an RTO as follows:

> MISO divides its operations into categories, including "Day 1" operations (dealing with security, outages, tariffs, transmission-line congestion and energy imbalances, billings and settlements, and market monitoring) and "Day 2" operations (implementing a competitive wholesale market for electricity, including locational marginal pricing and financial transmission rights).[190]

148. MISO charges member utilities like Minnesota Power various administrative costs associated with the MISO Day 2 market. The Commission has determined that utilities, including Minnesota Power, can recover MISO Day 2 costs through the FCA, with the exception of MISO Schedule 16 and 17 charges. Schedule 16 and 17 charges were determined to be administrative and not energy in nature. For that reason, Schedule 16 and 17 costs are recovered through base rates rather than through the FCA. In an Order entered on December 20, 2006 ("*MISO Day 2 Order*"), the Commission prescribed the following treatment for MISO Schedule 16 and 17 deferred costs:

> 2. Each petitioning utility may use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 1,2005. Each utility may continue deferring Schedule 16 and 17 costs without interest until the earlier of the utility's next electric rate case or March 1, 2009. By March 1, 2009, the utility shall begin amortizing the

[190] *ITMO Xcel Energy's Petition for Affirmation that MISO Day 2 Costs are Recoverable Under the Fuel Clause Rules and Associated Variances, et al*, Docket No. E-002/M-04-1970 (Commission Order Authorizing Interim Accounting For Miso Day 2 Costs, Subject To Refund With Interest issued April 7, 2005) (http://www.puc.state.mn.us/docs/orders/05-0025.pdf).

balance of the deferred Day 2 costs through March 1, 2012, unless and until the utility has a rate case addressing the utility's proposal for recovering the balance.

3. In its next rate case a utility may seek to recover Schedule 16 and 17 costs at an appropriate level of base rate recovery. The utility may not increase rates to recover MISO administrative costs unless the costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. However, a utility may seek to recover Schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a rate case, subject to final Commission approval.[191]

149. In this rate case, the Company's filing seeks test-year recovery of MISO Schedule 16 and 17 costs relating to two different periods:

1) The test-year period of July 1, 2008, to June 30, 2009, in the amount of $1,326,227 (Minnesota jurisdictional basis), with no rate base treatment; and

2) Deferred costs for the period April 2005, to June 30, 2008 in the amount of $1,490,664.[192]

150. The Commission described this cost recovery mechanism as follows:

> Each petitioning utility may use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 1, 2005 [the start of Day 2]. Each utility may continue deferring Schedule 16 and 17 costs without interest until the earlier of the utility's next electric rate case or March 1, 2009.[193]

151. The OES agrees that MP has demonstrated ratepayer benefits arising from participation in the MISO Day 2 market and that MP has allocated the current test-year period administrative costs between shareholders and retail ratepayers in a fair and reasonable manner.[194] The OES therefore accepts MP's proposal for treatment of current test-year MISO Schedule 16 and 17 costs, and the test year amount of $1,326,227 is not in dispute between MP and the OES.

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[191] *Order Establishing Accounting Treatment for MISO Day 2 Costs*, PUC Docket No. E017/M-04-1970 (December 20, 2006)("*MISO Day 2 Order*") at 17. https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3650720.
[192] Ex. 95A, Campbell Direct, at 9-10.
[193] *MISO Day 2 Order* , Ordering Paragraph 2.
[194] Ex. 95A, Campbell Direct, at 8; Ex. 102, Campbell Summary Statement, at 1.

152. MP calculated the recovery amount for deferred costs by taking its budgeted total deferred costs of $4,471,991 on a Minnesota jurisdictional basis and proposing that the deferred costs be amortized on a three-year schedule and be given rate base treatment.[195] The OES noted that the amount of deferred cost that the Company originally sought was its budgeted amount, not the historical amount; the OES also argued that the Company should use a five-year amortization schedule and that deferred MISO Schedule 16 and 17 costs should not be given rate base treatment.[196]

153. The Company subsequently agreed that the total sum of the deferred costs under consideration should be the amount that MP actually incurred, resulting in a reduction of $48,511 and total deferred cost of $4,423,480. The Company and the OES do not agree on whether a five-year or three-year amortization period should be used, or whether the deferred amount should be afforded rate base treatment.[197]

## A. Schedule 16 and 17 Deferred Costs Amortization Period.

154. Selecting a reasonable amortization period is important because ratepayers will continue to pay the deferred MISO Day 2 costs in base rates until MP files its next rate case and may overpay significantly if MP does not file another rate case within three years. For example, the Company filed its last rate case fourteen years ago, well beyond the amortization periods for rate case expenses that were approved in the 1994 rate case.[198]

155. The OES maintains that the amortization period for deferred MISO Schedule 16 and 17 costs should be set at a level which reasonably reflects when MP is likely to file its next rate case.[199] The OES used MP's history of filing rate cases to determine that MP's average time between rate cases is five years. The OES concluded that the appropriate amortization period for these expenses is five years.[200]

156. MP contends that the Commission already has established a three-year amortization period for deferral of MISO Schedule 16 and 17 costs by ordering that by March 1, 2009, utilities "shall begin amortizing the balance of the deferred Day 2 costs through March 1, 2012, unless and until the utility has a rate case addressing the utility's proposal for recovering the balance."[201] However, the OES contends that the Commission was not

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195 *Id*.
196 Ex. 96, Campbell Surrebuttal, at 2, 9; Ex. 102, Campbell Summary Statement, at 2.
197 OES Brief, at 86.
198 Ex. 96, Campbell Surrebuttal, at 6; Tr. Vol. 5 at 168 (Campbell).
199 Ex. 96, Campbell Surrebuttal, at 6.
200 OES Brief, at 88-90; *see also* discussion in Findings 237-239, *infra*.
201 Ex. 33, Seeling Direct, at 7-8, (referring to *ITMO Xcel Energy's Petition for Affirmation that MISO Day 2 Costs are Recoverable Under the Fuel Clause Rules and Associated Variances*, Docket No. E-002/M-04-

establishing the amortization period to be used in utility rate cases, nor was it binding itself in this or other future rate cases.[202]

157. The Commission's *MISO Day 2 Costs Order* does not establish an amortization period for these costs. The ALJ has recommended elsewhere in this report that the Commission accept Minnesota Power's proposal to file another rate case within three years by directing the Company to do so. If the Commission accepts that recommendation, it should allow Minnesota to amortize deferred MISO Schedule 16 and 17 costs on a three-year schedule. If the Commission does not accept that recommendation, it should follow the OES's recommendation to direct the Company to amortize those costs over a five-year period.

**B. Propriety of Adding Schedule 16 and 17 Deferred Costs to Rate Base.**

158. In addition to recovering deferred MISO 16 and 17 costs through an amortization schedule, as discussed above, Minnesota Power has proposed to include in its rate base the unamortized balance of those deferred MISO 16 and 17 costs. Based on information supplied by the Company, this would increase the rate base by $2,948,987.[203]

159. Minnesota Power argues that because those costs originate as an expense, the delay between payment and recovery warrants treating the unamortized amount as an investment, like any other prepaid expense. The Company therefore argues that it should be able to earn a return on the amounts not paid in the test year.[204] Additionally, MP argues that the Commission has not ruled out placing Schedule 16 and 17 Deferred Costs in a utility's rate base. It relies on the fact that although the MISO Day 2 Cost Orders did not allow utilities to include interest during the period when the costs were being deferred, the Order did not preclude the inclusion of those unamortized deferred costs in rate base in a rate case.[205]

160. The OES argues against rate base treatment of deferred Schedule 16 and 17 deferred costs. It argues first that the Company's proposal to place those costs in the rate base is inconsistent with ratemaking principles in that returns are generally allowed only for capital costs and that deferred MISO Schedule 16 and 17 costs are expenses and should be treated as traditional expenses are treated, without a return. The OES also asserts that that the Commission already addressed this issue in Otter Tail Power Company's most recent rate case and did not allow Schedule 16 and 17 deferred costs

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1970 (Commission Order issued December 20, 2006) (*MISO Day 2 Costs Order*) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3650720).
[202] Ex. 96, Campbell Surrebuttal, at 4-6;.
[203] Ex. 52, Podratz Rebuttal, Sched. 3.
[204] *Id*. at 9.
[205] Ex. 52, Podratz Rebuttal, at 9.

to be place in that utility's rate base. Finally, the OES argues that the Commission's statement in the *MISO Day 2 Costs Order* that "[e]ach utility may continue deferring Schedule 16 and 17 costs *without interest* until the earlier of the utility's next electric rate case or March 1, 2009," expressly precludes rate base treatment of those costs. The OES therefore recommends that the Commission require MP to remove the deferred MISO Schedule 16 and 17 costs from rate base and treat these expenses as expenses.[206]

161. The ALJ concludes that the proposition that investors should be given a return (rate base treatment) on deferred Schedule 16 and 17 costs is unreasonable and should be rejected. First, the OES and the Company both agree that although ratepayers will pay for both the current MISO Schedule 16 and 17 costs as well as the deferred costs from the period of April 1, 2005 to June 30, 2008, the Company has been allowed to retain (not defer in order to return to ratepayers) any revenues associated with its activities in the MISO Day 2 energy market. Moreover, the Commission has already decided that the utilities cannot recover interest expenses on the deferred MISO administrative costs. Paragraph 2 of the MISO Day 2 Costs Order explicitly states that deferral of Schedule 16 and 17 costs was to be "without interest." Placing the costs in rate base would be in direct contradiction with that decision. Finally, as Ms. Campbell pointed out, these costs are expenses and are generally only allowed interest, not a return. The MISO administrative costs are clearly not capital costs to which a return would be applied, if allowed. For the reasons set forth above, the ALJ recommends that the Commission direct Minnesota Power to remove deferred MISO Schedule 16 and 17 costs from the rate base.

**C. Ontario Path Wheeling Revenues and Related Costs.**

162. "Other Wheeling Revenues" are revenues generated from MP's transmission facilities through the MISO tariff, when utilities other than MP use, or wheel, the Company's transmission lines to move energy across MP's system. As with MP's generation assets, MISO requires that utility's transmission assets be available for use by other utilities, if the lines are not fully used to serve MP's retail customers. Other utilities pay MISO for their wheeling activities, and MISO, in turn, pays those revenues to MP. Because transmission assets are funded by ratepayers as part of MP's rate base, ratepayers must be credited with wheeling revenues from MISO that are associated with such assets.[207]

163. The OES first noticed that Minnesota Power had made a very large, unexplained reduction in test year Other Wheeling Revenues of $5.8 million on a total Company basis, when compared with the Company's levels from previous years.[208] In response to the OES's

[206] Ex. 95A, Campbell Direct, at 13-14.
[207] Ex. 95A, Campbell Direct, at 27.
[208] Ex. 95A, Campbell Direct, at 28.

discovery, MP admitted in July 2008 to having omitted $4 million in revenue from MISO, which it had derived from wheeling energy across its transmission system. The Company's explanation was that it had incorrectly assumed that MISO would change its transmission revenue sharing allocation method, which would have resulted in a reduction in test year Other Wheeling Revenues. However, MISO never made that change. Because of that, both MP and OES agree that an additional $4,070,155 in revenue needs to be added into rates for Other Wheeling Revenues from MISO.[209]

164. When the Company recognized the increase in Other Wheeling Revenues, MP noted that it also did not include in the test year any expense associated with MISO point-to-point transmission service for the delivery of power the Company purchases from Ontario. MP explained that the anticipated change in MISO's revenue sharing methodology would also have made the "Ontario Path" for delivery of energy available to the Company at no cost using MISO network transmission service. But the change in methodology did not occur, and Minnesota Power has therefore proposed an upward adjustment in expenses for the Ontario Path of $3,590,268, which translates to a Minnesota jurisdictional adjustment of $2,822,776.[210]

165. The OES objected to the inclusion of those costs, particularly since the Company did not make documentation available to support them until the evidentiary hearing. The OES maintains that MP's documentation is untimely and inadequate to support the claimed expenses and that the claimed $2.8 million in costs should not be allowed. In the alternative, the OES proposes that cost recovery should be limited to the $1.9 million that was documented as on-going transmission costs by MP, based on invoices that the Company provided at the hearing.[211]

166. Before the evidentiary hearing, MP expressly advised the OES that the expenses associated with the Ontario Path revenues had been omitted from rate recovery.[212] In response, the OES advised Minnesota Power of the minimum information OES would need for consideration of MP's claimed Ontario Path wheeling expenses:

- MP's purchase power contract with Ontario for 2009 and 2010 (to ensure transmission expense being built into rates is an on-going expense);

- Proof that the purchase power contract is being used to serve retail customers;

- Information to support that the transmission expenses are real (actual invoices);

[209] Ex. 102, Campbell Summary Statement, at 1.
[210] Ex. 53, Podratz Rebuttal, at 11.
[211] Ex. 102, Campbell Summary Statement, at 2; Ex. 100, Ontario Transmission Path.
[212] Ex. 53, Podratz Rebuttal, at 11.

- Information to show that these transmission expenses are not already embedded in current rates;

- Any other information MP considers appropriate to support their case for cost recovery purposes.[213]

167. MP expressly indicated that the expenses associated with the Ontario Path revenues had been excluded from rate recovery.[214] Prior to the hearing, MP reviewed the test year expenses again and concluded that the Ontario Path expense had not been previously included.[215] MP noted that the original test year budgeted total O&M expense for Transmission of Electricity of Others was only $1,349,610. MP indicated that this amount is much smaller than the total Ontario Path transmission expense of $3.6 million. This supports the conclusion that the Ontario Path expense was not included in the test year budget.[216]

168. The OES has expressed legitimate concerns that expenses could have been "double counted" through MP's failure to identify these expenses from the intital filing of this proceeding. MP bears the burden of proof to show what costs are incurred in providing electricity to customers. On this issue, MP has provided both an adequate explanation and a sufficient factual basis for inclusion of the Ontario Path expenses in calculating rates. The ALJ recommends that the Commission include the Ontario Path costs in calculating base rates.

## VI. AREA PLAN O&M EXPENSES.

169. On October 14, 2005, Minnesota Power filed an application with the Commission in Docket No. E-015/M-05-1678 seeking its approval to proceed with projects designed to reduce the pollution emitted from some of its electric generators in the Arrowhead region of Minnesota. The Company called its proposal the "Arrowhead Regional Emission Abatement Plan" or "AREA" Plan.[217] The AREA Plan is part of the Company's comprehensive emission compliance plan, and it includes the Taconite Harbor and Laskin Energy Centers.[218] The Commission approved the AREA plan subject to certain conditions, one of which was:

> If the revenues collected by the rider differ from the AREA Plan's costs, parties may propose compensating rider adjustments once all of the

[213] Ex. 96, Campbell Surrebuttal, at 22.
[214] Ex. 53, Podratz Rebuttal, at 11.
[215] Tr. Vol. 3, at 78-79 (Podratz).
[216] *See* Ex. 6, Rate Case Volume IV, work paper MAP 13-2, FERC Account 565.
[217] *ITMO the Application for Approval of Minnesota Power's Arrowhead Regional Emission Abatement Proposal*, Docket No. E-015/M-05-1678 (Commission Order issued June 13, 2006)(*AREA Order*) at 1 (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3134125).
[218] Ex. 43, Hodnick Direct, at 6.

AREA Plan components are in service or in the Company's next general rate case, whichever is sooner. But in no event shall the Company calculate the amount it recovers through the rider on the basis of more than $53.9 million for capital costs and $4.07 million for annual operating and maintenance expenses. If the actual costs of the AREA Plan exceed these caps, the Company shall report this fact to the Commission to enable a Commission review [of] the matter.[219]

170. On March 31, 2008, Minnesota Power filed another application with the Commission in Docket No. E-015/M-05-1678 in which, among other things, the Company sought to recover AREA Plan annual O&M expenses in excess of the $4.07 million cap that the Commission imposed in its *AREA Order*.[220] By Order entered on August 5, 2008, the Commission disposed of that petition in the following way:

Dismissed the petition without prejudice.

The Commission will address these issues in the Company's rate case.[221]

171. In this proceeding, Minnesota Power initially proposed to transfer the recovery of costs related to Laskin Units 1 and 2 and Taconite Harbor Units 1 and 2 from the AREA Rider to its base rates, thereby including $13,866,854 in AREA costs in the rate case, including $4,749,256 of O&M expenses.[222] The $4,749,256 in requested annual O&M expenses exceeds the cap established by the Commission on June 13, 2006, by $679,256.

172. The OES objected to inclusion of annual O&M costs that exceeded "the initial operation and maintenance (O&M) cap of $4.07 million that was established in the Commission's Order on June 13, 2006," [the *AREA Order*] and proposed a downward adjustment of $679,256 ($568,533 Minnesota jurisdiction) to account for the amount by which Taconite Harbor O&M costs exceed $4.07 million.[223] To address the OES's objection, Minnesota Power proposes to move its request for O&M costs that exceed than $4.07 million out of the rate case and into the AREA Rider docket for further review by the Commission but leave $4.01 million in the test year to be incorporated into the rate.[224]

173. In the ALJ's view, the positions that the parties' have expressed on this issue, to some extent,

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[219] *AREA Order*, at 12.

[220] *ITMO Minnesota Power's Petition to Implement its Arrowhead Regional Emission Abatement Rider for Taconite Harbor Unit 1*, Docket No. E-015/M-05-1678 (Petition filed March 31, 2008) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5047698).

[221] *ITMO Minnesota Power's Petition to Implement its Arrowhead Regional Emission Abatement Rider for Taconite Harbor Unit 1*, Docket No. E-015/M-05-1678 (Commission Order issued August 5, 2008) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5409809).

[222] Ex. 43, Hodnick Direct, at 6-7; Ex. 87A, Johnson Direct, at 21-22.

[223] Ex. 87A, Johnson Direct, at 22-23.

[224] Ex. 53, Podratz Rebuttal, Sched. 18 at 2; Tr. Vol. 3, at 258 (Podratz).

miss the mark. In a rate proceeding, Minn. Stat. § 216B.03 provides that "[e]very rate made, demanded or received by a public utility...shall be just and reasonable...Any doubt as to reasonableness should be resolved in favor of the consumer." Costs that are uncertain, unpredictable, or unreliable, are unreasonable and should not be recovered in base rates. The issue here is not whether this rate case or the AREA rider docket is the appropriate forum for Minnesota Power to request the Commission to approve O&M expenses in excess of the $4.01 million cap set in its *AREA Order*. This issue here is a ripeness issue—that is, whether at this point in time—i.e., during this rate proceeding—the $679,256 ($568,533 on a Minnesota jurisdictional basis) in annual O&M costs in excess of the cap that the Company is seeking to recover are certain, predictable, and reliable. The ALJ concludes that they are not. In response to questioning by the ALJ, Company witness, Ms. Hodnick, offered the following testimony:

> And we installed -- because Taconite Harbor is a small facility -- it's 225 megawatts, three 75-megawatt units -- there are not a lot of very economical solutions to apply on a facility of that type to do emission reductions. So we tried some, we call it cutting-edge technology up there and had great success with NOx reduction, moderate success as far as mercury reduction, and then some challenges with SO2 reduction. And we're continuing to work with our own staff and with the vendor that sold us the technology to tune that to see if we can improve the emission reduction performance. And until we get that tuned, the amount of sorbents and reagents we need to do that will be unknown, and so the O&M costs will be unknown until we reach that conclusion.[225]

In short, Minnesota Power has not yet established that $679,256 ($568,533 on a Minnesota jurisdictional basis) of annual O&M costs in excess of the $4.07 million cap are certain, predictable, and reliable and therefore reasonable to include in the rate.

174. In its *AREA Order*, the Commission did not definitively conclude that AREA Rider O&M costs of $4.07 million were reasonable. It left open the possibility of a true up that might establish actual costs below the cap of $4.07 million cap. The ALJ therefore recommends that if the Commission concludes that a true up is no longer necessary, it allow AREA O&M costs of $4.07 million to be included in the rate, without prejudice to allow the Company to request a compensating rider adjustment upon a showing that there are certain, predictable, reliable, and otherwise reasonable O&M costs in excess of the $4.07 million cap.

## VII. INCENTIVE COMPENSATION.

175. Minnesota Power proposes to include approximately $6,823,793 of employee incentive compensation expenses in the test year. That budgeted amount is divided between three programs: Results Sharing ($4,242,510); Annual Incentive Program (AIP)(

[225] Tr. Vol. 3, at 37-38 (Hodnick).

$1,180,844); and Long Term Incentive Program (LTIP) ($1,400,439).[226] All MP employees participate in the Results Sharing Plan, the AIP applies to 90 management employees, and the LTIP applies to 43 management employees of MP and ALLETE's corporate operation.[227]

## A. Incentive Compensation Levels.

176. The Results Sharing incentive is paid out when and if ALLETE meets a target level financial performance (including the cost of paying a target level award). The minimum amount of the payout is 3 percent of base compensation. If Key Result Area (KRA) goals are accomplished in the three areas of employee safety, environmental compliance, and system reliability, the incentive payout is increased to 5 percent of base compensation. If financial performance is sufficiently above the target level and all KRA goals are achieved, the Company increases awards proportionately up to a maximum of 15 percent of base compensation.[228] Since inception of the Results Sharing program in 1991, Results Sharing awards have averaged 6 percent of base compensation.[229]

177. Participants in the AIP are eligible for target level awards ranging from 10 percent of base compensation to 50 percent of base compensation. As described by MP, "A participant's (i) base compensation plus (ii) the AIP target award opportunity plus (iii) the 5 percent target level Results Sharing award opportunity equates to total compensation for employees participating in AIP and Results Sharing." MP included in the test year budget an amount reflecting 62.5 percent of the total possible incentive compensation (AIP and Results Sharing), since that was the amount actually paid out in 2007. 230

178. MP indicates that the total compensation available to employees eligible for the LTIP is "[a] participant's (i) base compensation plus (ii) target award opportunities under Results Sharing and the AIP plus (iii) the target award opportunity from LTIP equates to total direct compensation." Target performance to trigger LTIP awards is weighted, with the greatest emphasis on earnings. The Company maintains that the overall amount of incentive compensation is set so that the total compensation "is near the midpoint of the competitive market level." MP indicated that "[g]oal achievement below the target performance level would result in no or lower incentive awards being paid and below market compensation for management." In this proceeding, MP seeks to recover 100 percent of the LTIP target compensation in rates.[231]

179. Minnesota Power argues that its incentive compensation proposals are needed to provide

[226] Ex. 103, Lusti Direct, at 20.
[227] Ex. 41, Carter Direct, at 3.
[228] Ex. 41, Carter Direct, at 5-6.
[229] Ex. 41, Carter Direct, at 11.
[230] Ex. 41, Carter Direct, at 13-14.
[231] Ex. 41, Carter Direct, at 16-17.

sufficient compensation to attract, motivate, and retain talented employees, and are necessary to provide high quality service to customers. To attract and retain employees with the necessary talent and ability, MP argues that its total compensation package must be competitive. In 2007, the Company commissioned a study by Hewitt Associates which determined that the base salaries of MP's executive officers were near the 50th percentile of energy services company benchmarks. That study also indicated that annual incentive compensation targets fell near the 50th percentile of energy services company benchmarks. The only exception was ALLETE's Chief Executive Officer (CEO) position, which fell below the 50th percentile of those benchmarks.[232]

180. The Company further argues that it "is differently situated from other utilities, based largely on the age of its workforce and its geographic location in the state. With the changing demographic of the state's workforce as a whole, which is more pronounced for Minnesota Power … incentive compensation is becoming increasingly necessary to attract new workers."[233]

**B. OES Proposed Limits on Results Sharing and AIP.**

181. In response to the Company's incentive compensation proposals, the OES noted that in its prior general rate case orders, the Commission has followed a practice of limiting incentive compensation to no more than 25 percent of base compensation. Accordingly, the OES proposed a cap of 20 percent for AIP costs, together with the 5 percent cap for results sharing costs. The OES maintains that these limits would provide the Company with recovery of combined incentive compensation up to 25 percent of base salary. The OES also recommends that $167,143 in test-year AIP incentive compensation expenses of be excluded to keep the total within a 25 percent cap. The OES argues that its recommendation is consistent with Commission precedent.[234]

182. In response, MP argues that its proposal would recover no more than 36.5% of base compensation for the Results Sharing and AIP programs combined.[235] The Company maintains that "the high end would only be achieved if the Company reaches its AIP targets, which would not only keep the Company sound, but also ensure such specific benefits to the utility such as ensuring the Company's ability to increase its supply of renewable energy and providing leadership development and succession planning for Minnesota Power."[236] MP also argues that it must offer a plan such as the AIP to offer competitive salaries in its "difficult market,"[237] and that "denying recovery of these costs

[232] Ex. 41, Carter Direct, at 21-22.
[233] MP Brief, at 44 (citing Tr. Vol. 3, at 13-14 (Carter)).
[234] Ex. 104, Lusti Surrebuttal, at 10.
[235] Ex. 41, Carter Direct, at 3-4.
[236] MP Brief, at 45 (citing Ex. 41, Carter Direct, at 13).
[237] *Id*.

sends the message that either a larger percentage of salaries should be allocated to base compensation (which is a potentially more expensive method of employee compensation, and would be earned regardless of Company performance), or that market-level compensation should not be paid."[238]

183. In reply, the OES noted that the Commission's Order in MP's last rate case indicated a concern with the wide range of the incentive compensation awards available to MP management employees:

> Regarding incentive compensation, the Commission has found in previous rate cases that incentive compensation plans can be effective management tools when properly designed and administered. In this case, the Commission finds that the two incentive compensation programs proposed by MP (Results Sharing and Incentive Compensation for Officers and Management) have been appropriately designed.
>
> The Commission will approve them with one modification. Perception of favoritism or inequity in the administration of the incentive program could have negative repercussions for employee morale and consequently negatively affect their productivity. Such a wide range of award (up to 60 percent of base pay) substantially increases the possibility of such perceptions. In addition, as the Commission has previously found, offering key decision makers large financial rewards for producing short-term shareholder benefits does not promote regulatory efficiency or the longterm fortunes of the Company. The Commission, therefore, will limit annual incentive payments to 15 percent of an individual's base pay, the same maximum level available to all other employees.[239]

## C. OES Proposed Disallowance of LTIP.

184. As the OES observed, the Company proposes to pay incentive compensation under the LTIP in addition to that obtainable under both Results Sharing and AIP. Referring to the Commission's practice of excluding from test year expenses any that incentive compensation that exceeds 25 percent of base compensation, the OES proposes that 100% of the LTIP expenses be disallowed.[240]

185. The Company's proposed incentive compensation plan is strikingly similar to that rejected in the Company's last rate case. As justification, the Company asserts that limiting the total incentive compensation to 25 percent of base compensation will not meet the

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[238] *Id*.

[239] *ITMO the Application of Minnesota Power for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota*, Docket No. E015/GR-94-001, at 23-24 (Commission Finding of Fact, Conclusions of Law, and Order issued November 22, 1994)(*MP 1994 Rate Order*).

[240] OES Brief, at 41.

Company's need to attract skilled employees and motivate them to provide excellent service. However, the Company has offered little evidence that it suffers from a sufficient competitive disadvantage in attracting skilled and talented employees to warrant a departure from the limits the Commission has previously imposed on incentive compensation. Evidence that its executive compensation annual incentive compensation targets are at the midpoint of energy services company benchmarks does not necessarily establish a competitive disadvantage. Neither is there persuasive evidence supporting the Company's assertion that its geographic position within the state places it at a competitive disadvantage. Although location in a major metropolitan area may provide amenities that are attractive to some prospective employees, the reverse may also be true of a northern Minnesota location. Moreover, the Commission's Otter Tail Power decision suggests that geographic location does not necessarily warrant a departure from past practice.[241] Finally, in its description of the LTIP program, the Company concedes that there is emphasis on earnings as a goal. That goal primarily benefits shareholders, not ratepayers. If ALLETE's other business activities require a higher degree of executive and technical talent than other undiversified public utilities, then shareholders should bear that cost.

186. In summary, the ALJ concludes that the OES proposal to allow the cost of the Results Sharing with a 5 percent cap and the AIP with a 20 percent cap, but removing the cost of the LTIP in its entirety, will both benefit ratepayers and result in rates that are just and reasonable. The ALJ therefore recommends that the Commission approve that proposal.

**D. Refund Mechanism.**

187. Minnesota Power had acknowledged that its incentive compensation plans do not require the Company to pay the target amounts in any particular year, that the Company has reserved the right to discontinue all its incentive compensation plans, and that there is no obligation for the Company to adopt new plans, even when rates charged to customers that are based on having that expense. As a consequence, the OES is also recommending that any incentive compensation that is included in base rates but that is not actually paid to MP's officers and employees be refunded to ratepayers. Although Minnesota Power takes the OES's proposal to mean that refunds will take place if the incentive compensation plan is changed to some different form of incentive plan,[242] that does not appear to be what the OES is proposing. The ALJ understands that the proposed refund mechanism would require tracking of the amounts actually paid in incentive compensation and only require refunds of any amount not paid to employees up to the total amount of expense allowed by the Commission.

[241] *Otter Tail Power 2008 Order*, at 47.
[242] MP Brief, at 46.

188. A refund mechanism for incentive compensation would be consistent with Commission precedent. As the Commission stated in a prior rate case:

> In the original Order, the Commission expressed strong disapproval of the Company's retention of the right not to make incentive payments earned under the plan. The Commission continues to view this as an inappropriate transfer of risk from shareholders to ratepayers and as inconsistent with the test year concept on which rates are based. The Commission will therefore require the Company to record all earned but unpaid incentive compensation recoverable in rates under this Order for future return to the ratepayers. This will adequately protect ratepayers' interests and prevent erosion of the test year concept.[243]

189. In fact, the Commission followed that approach in the *2005 Xcel Energy Rate Case* where it ordered:

> The Commission concurs with, accepts, and adopts the ALJ's recommendation on this issue, which was to cap individual incentive compensation payments at 25% of an employee's base salary; to base total, company-wide incentive compensation on amounts actually paid out between 2002 and 2005; and to continue the tracking and refund mechanism established in the Company's 1992 rate case.[244]

190. The Commission also followed this approach to incentive compensation included in rates but not paid in its *NSP Gas Rate 2007 Order*:

> The Commission finds that the Company's proposed level of incentive compensation in this proceeding is reasonable and will approve it. The Commission also adopts the ALJ's finding and will require Xcel to refund amounts included in the test year for incentive compensation that were not actually paid.[245]

191. In its most recent rate order, the Commission stated:

> The Commission also concurs with the Administrative Law Judge that the Company should be required to establish a mechanism to refund to ratepayers any incentive compensation included in rates that is not actually paid. While it is probable that the Company will continue to make

[243] *ITMO Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota,* Docket No. E002/GR-92-1185, at 7-8 (Commission Order After Reconsideration issued January 14, 1994).
[244] *2005 Xcel Energy Rate Case*, *supra*, Commission Order, at 18.
[245] *NSP Gas Rate 2007 Order*, at 13.

> payments under the incentive compensation plan throughout the period that rates will be in effect, the terms of the plan do not require the Company to do so. In fact, the plan explicitly grants the Company the right to discontinue it at any time.[246]

192. Maintaining a tracking mechanism and refunding unpaid incentive compensation already included in rates would not be unduly burdensome for the Company and would represent a reasonable condition to allowing reasonable incentive compensation costs to remain in the rate base, and the ALJ therefore recommends that the Commission include such a condition its final order in this proceeding.

## VIII. AIRCRAFT COSTS.

193. In its rate proposal, the Company identified a total of $1.3 million in ALLETE aircraft costs during the test year. Of that total, 92% or $1.2 million was allocated to Minnesota Power.[247] This amount is approximately $600,000 lower than the Company's 2007 expenses on a Minnesota jurisdictional basis.[248]

194. On March 8, 2007, the Commission issued an Order approving Minnesota Power's acquisition of an aircraft that MP had previously shared with a spun-off subsidiary (Aircraft Ownership Order). At that time, the Commission required Minnesota Power to include in its next rate case filing a cost benefit analysis addressing whether (i) the benefits of allocating 100% of an aircraft to Minnesota Power exceeds the costs; (ii) whether the aircraft ownership allocated to Minnesota Power is necessary in the provision of utility service; and (iii) whether the arrangement is beneficial compared to using alternative transportation.[249]

195. Previously, in 2006, MP had hired an independent assessor, Avicor Aviation (Avicor), to determine whether possession and use of a private corporate aircraft was appropriate. Avicor determined that the corporate aircraft provides a cost benefit to the company compared to commercial airline flights and "strongly recommend[ed]" that "ALLETE continue to utilize a corporate aircraft for its business needs."[250] Regarding specific issues, Avicor determined:

> [B]ased on our review of the trips that were taken on the [aircraft], it is apparent that the [aircraft is] used with the greatest frequency for trips to

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[246] *Otter Tail Power 2008 Order*, at 47.
[247] Ex. 76A, Lindell Direct, at 35.
[248] Ex. 24, DeVinck Direct, at 9.
[249] *ITMO Minnesota Power's Petition for Approval of Aircraft Ownership Transfer Between ALLETE, Inc. and ADESA, Inc*., Docket No. E-015/PA-06-1589 (Commission Order issued March 8, 2007)(*Aircraft Ownership Order*) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3880852).
[250] Ex. 24, DeVinck Direct, Sched. 1, at 17.

> locations that are difficult to access in a timely manner by commercial carrier. …
>
> Based on the travel patterns assessed, ALLETE utilizes its Hawker 700A to ensure the efficiency of its employees[.]…
>
> One small note about productivity in relation to ALLETE and where it is located – consistent and timely commercial lift is clearly a problem at DLH [Duluth International Airport].[251]

In its report, Avicor concluded that it was evident from the flights that were undertaken that the aircraft are being used to move key individuals where they need to be when they need to be there, without wasting their time and productivity.[252]

196. The OAG/RUD conducted a trip-by-trip analysis of the usage of the aircraft and identified several trips that it considered to be problematic. One such trip was a flight from Duluth to Scottsdale, Arizona (Phoenix) by ALLETES's CEO and a MP Vice President and those officers' spouses. MP was allocated $11,461.00, or 84%, of that trip's costs. Another trip viewed as problematic involved ALLETE's CEO, traveling alone from Duluth to Fort Meyers, Florida. MP was allocated 72%, or $11,399 of the overall cost of that trip.[253]

197. The OAG/RUD questioned the business purpose of the Scottsdale trip and argued that none of the costs of that trip were appropriate for allocation to the regulated operation. The OAG/RUD also argued that using a private jet for trips to Fort Myers, Florida and Scottsdale Arizona, rather than using commercial flights, was imprudent.[254] In response, MP stated that the business purpose of the Scottsdale trip was for an Edison Electric Institute (EEI) meeting. However, the Company did not address why using a corporate aircraft, as opposed to using scheduled commercial flights, was necessary.

198. The OAG/RUD also questioned the regulatory necessity of using the corporate aircraft for multiple trips to Florida, including popular vacation destinations like Fort Myers, Naples and Daytona Beach, as well as trips to readily accessible destinations like Dulles airport in Washington, D.C., Denver, Colorado, and Scottsdale, Arizona.[255]

199. In response, Minnesota Power asserted that flights to Florida and other locations that were allocated in whole or in part to Minnesota Power did relate to MP's business (citing as an example ALLETE board of directors meetings that are conducted in Florida). The

[251] Ex. 24, DeVinck Direct, Sched. 1, at 2, 15.
[252] Ex. 24, DeVinck Direct, Sched. 1, at 15.
[253] Ex. 76A, Lindell Direct, at 37-38.
[254] Ex. 76A, Lindell Direct, at 37-38.
[255] OAG/RUD Reply, at 22.

Company maintains that when the trip has a Minnesota Power purpose, flight costs have been allocated to Minnesota Power in appropriate proportion to the utility benefit of the flight.[256] Nevertheless, after the OAG/RUD questioned the regulatory purpose of a flight to Fort Myers for which the costs had been allocated 72.1% to regulated operations and 27.9% to non-regulated operations the Company discovered that the CEO had been engaged in interviews for ALLETE Properties and that 100% of the costs should therefore have been assigned to ALLETE Properties.[257]

200. Based on its review and findings, the OAG/RUD argues that the evidence it has presented calls into question Avicor's 2006 conclusion that ALLETE uses the corporate jet to fly to destinations that are difficult to access via commercial flights. The OAG/RUD also asserts that "ALLETE's corporate aircraft is used as an executive perk, which Minnesota Power ratepayers struggling through an economic crisis should not be required to fund."[258] Rather than requiring the Company to deduct from the expense figure the cost of individual corporate aircraft flights, for which there was no apparent benefit to ratepayers, the OAG/RUD has recommended that all expenses associated with ALLETE's corporate aircraft be excluded from Minnesota Power's rates.

201. Minnesota Power has objected to the OAG/RUD 's proposal to disallow all test year corporate aircraft costs. In so doing, the Company notes that the OAG/RUD is not recommending that if those costs are disallowed, the Company should be allowed to recover as an offset the costs of commercial flights that Minnesota Power would have incurred if the corporate aircraft was never used. The Company also argues that there should also be an offset to any disallowance for the productivity that that is lost when its employees must use commercial flights.[259]

202. Minnesota Power further maintains that ALLETE has carefully limited the use of its corporate aircraft. It cites the following procedures to demonstrate that it has limited use of the corporate aircraft to appropriate situations:

> (1) commercial travel rates and schedules must be carefully considered first; (2) more than one employee generally must be traveling on the corporate aircraft for its use to be approved; (3) an employee requesting use of the aircraft must prepare a Company Aircraft Travel Request/Approval form before flying; (4) travel must be approved in advance by a Vice President; (4) ALLETE CFO Mark Schober reviews the forms monthly to ensure appropriate use; and (5) ALLETE's Internal Audit

[256] Ex. 25, DeVinck Rebuttal, at 16-17.
[257] *Id*. at 16.
[258] OAG/RUD Reply, at 21-22.
[259] MP Brief, at 47.

Department audits aircraft usage annually.. In addition, flight logs are completed for each trip.[260]

203. Under the *Aircraft Ownership Order*, the Commission required Minnesota Power to include in its next rate case filing a cost benefit analysis demonstrating that the benefits of allocating 100% of an aircraft to Minnesota Power exceeds the costs; that the aircraft ownership allocated to Minnesota Power is necessary in the provision of utility service, and that the arrangement is beneficial when compared to using alternative transportation.[261] In addition to that, the Commission also ordered that:

> ALLETE shall show and provide adequate support for these allocations of aircraft costs in its next rate case. Additionally, ALLETE shall explain and support in the context of its next rate case whether or not the entire aircraft should be included in rate base for regulated purposes or whether some proportional share of the aircraft equal to regulated use should be included in rate base.[262]

204. Although Avicor's report does not represent a cost-benefit analysis, as that term is commonly understood, it does meet at least one of the criteria that the Commission established in the *Aircraft Ownership Order*. It does establish that use of a corporate aircraft is beneficial in comparison to using alternative transportation in many situations. Moreover, the *Aircraft Ownership Order* does not appear to require the Company to submit a formal benefit-cost analysis unless it proposes to allocate 100% of the aircraft's cost to Minnesota Power. However, the Company has not chosen to do that. Rather, it has offered trip by trip information on the proportional share of the aircraft's cost that it believes equates to the aircraft's regulated use to support inclusion of the allocated costs in base rates. In other words, the Company has complied with the alternative method of allocating the aircraft's costs that the Commission appears to have afforded in its *Aircraft Ownership Order*. It also has offered explanations of why each was necessary in the provision of utility service when that was otherwise not readily apparent.

205. The OAG/RUD discovered some apparent discrepancies in Minnesota Power corporate aircraft cost allocations, but those discrepancies were not numerous in the context of dozens of flights. Whether the frequency and magnitude of the discrepancies that occurred are a sufficient basis to disallow all of the proposed corporate aircraft test year costs is ultimately for the Commission to determine. However, the ALJ does not consider the discrepancies that OAG/RUD's investigations revealed to be a sufficient basis and further finds that the Company has made a good faith effort to comply with

[260] Ex. 25, DeVinck Rebuttal, at 13-15 and Sched. 5.
[261] *Aircraft Ownership Order*, *supra.* The ALJ notes that the language of the Order is somewhat ambiguous on this point, and that one could also interpret it to mean that the Commission intended to require a benefit costs analysis even if a portion of each flight were allocated to Minnesota Power.
[262] *Aircraft Ownership Order*, *supra*.

how it interprets the Commission's Aircraft Ownership Order. Moreover, since neither the OAG/RUD, the OES, nor any other party has recommended adjustments to the test year corporate aircraft costs to reflect a lesser benefit to ratepayers than that claimed, the ALJ recommends that the Company's proposed corporate aircraft test year costs be allowed.

## IX. CORPORATE COST ALLOCATIONS.

### A. MP's Allocation Methods.

206. As previously discussed, Minnesota Power is an operating division of ALLETE, which also owns businesses that are not rate-regulated by the Commission. In this proceeding, the Company proposes to allocate certain costs from ALLETE to MP for inclusion in the test year expenses. In its Docket 1008 proceeding,[263] the Commission adopted a four-part hierarchical methodology to govern such allocations:

> 1) Tariffed rates shall be used for tariffed services provided to nonregulated activity.
>
> 2) Costs shall be directly assigned whenever possible.
>
> 3) If costs cannot be directly assigned, they shall be allocated based on an indirect cost-causative linkage to another cost category or group of cost categories for which direct assignment or allocation is available.
>
> 4) When neither direct nor indirect cost causation can be found, the costs are to be allocated using a general allocator.[264]

In the same Order, the Commission also adopted a default general allocator that uses the ratio of all expenses directly assigned or attributed to regulated and unregulated activities, excluding the cost of fuel, gas, purchased power, and the cost of goods sold.[265]

207. In the *Docket 1008 Order*, the Commission also recognized that cost allocations should be sufficiently flexible to reflect differences between utilities and differences in the characteristics of the unregulated entities:

> The Commission understands that utilities differ in many essential respects, including their participation in affiliated operations. The Commission believes that the hierarchical principles offer sufficient

[263] *ITMO an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Docket No. G,E999/CI-90-1008 ("Docket 1008)".
[264] *ITMO an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Order Setting Filing Requirement, Docket No. G,E999/CI-90-1008 at 4 (September 28, 1994) (*Docket 1008 Order*).
[265] *Docket 1008 Order* at 6.

> flexibility for each utility to develop appropriate allocation methodologies based on the principles.[266]

208. In its subsequent *Order Closing Docket 1008*, the Commission reaffirmed that a utility is allowed to deviate from the default approach in future rate cases when the utility establishes that:

> … its cost allocation principles produce similar results as would allocations following the recommended cost allocation principles,
>
> * * *
>
> or the public interest is better served by another method.[267]

209. The Commission's *Docket 1008 Order* establishes the burden that utilities must meet when they employ allocation principles that are different from those established by the Commission:

> Should a utility wish to base its cost separations on different principles, the burden of proof would be on that utility to prove that its cost allocation principles arrive at fully allocated costs, free of any cross-subsidization. The utility would have to show that the goals of fully allocated costing, as expressed in this and other Orders, are fully realized. The utility would have the burden of demonstrating that it considered all of its costs and that they are allocated to share burdens and benefits equitably between the regulated and nonregulated operations.[268]

210. As a division of ALLETE, Minnesota Power uses the same accounting methodology as ALLETE. At the time of its last rate case in 1994, Minnesota Power utilized the standard FERC Uniform System of Accounts for its chart of accounts (COA). That system gathered costs by responsibility center and FERC account, but did not allow for functional cost accumulation or activity cost reporting.[269] In 1998, Minnesota Power implemented the accounting system for allocating costs (BIS system) that it uses today. Its BIS system provides for (i) direct charging to specific "Lines of Business;" (ii) direct charging to non-regulated activities; (iii) direct charging and billing of costs incurred on behalf of subsidiaries and other entities; and (iv) proper allocation of unassigned charges for which it is not feasible to direct charge. The BIS system accumulates costs by function and segregates regulated and non-regulated activities and expenditures.[270]

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[266] *Docket 1008 Order* at 5.
[267] *Docket 1008*, supra, (Commission Order Finding Compliance, Exempting Northwestern Wisconsin, Requiring Preparation, and Closing Docket issued March 1, 1995) ("*Order Closing Docket 1008*").
[268] *Docket 1008 Order*, at 6.
[269] Ex. 24, DeVinck Direct, at 8.
[270] Ex. 24, DeVinck Direct, at 3-4.

211. On September 17, 2001, Minnesota Power filed a petition with the Commission that, among other things, requested the Commission's approval of the Company's accounting methodology for asset accounting and functional cost assignment for use in all future asset-related or cost-based proceedings before the Commission.[271] The Commission issued an Order in that docket on August 8, 2002, that approved MP's accounting methodology petition with certain conditions (August 8, 2002 Order). Among those conditions was a requirement that the Company meet with the Department of Commerce (now OES), the OAG/RUD, and Commission staff to review allocation methods and overall accounting methodology. The Commission also required MP to update the OES and Commission staff annually of changes to allocators.[272] As to the future effect of that meeting, the Commission stated:

> Finally, the Commission clarifies that this consultation and reporting is no substitute for the Commission's review of the merits of MP's allocators in MP's next rate case, where the Company will bear the burden of proof that its allocators are cost causative and fairly allocate costs.[273]

212. The meeting that the Commission specified in its Order of August 8, 2002, occurred on September 2, 2002. At that time, the Company advised the OES, OAG/RUD, and Commission staff that it did not have a general or default corporate allocator, but rather that it directly charges corporate costs or allocates.[274] Since September 2, 2002, Minnesota Power has made annual compliance filings in Docket No. E-015/M-01-1416 that have documented changes the Company made to its cost accounting systems during the preceding year.[275] The Company's most recent compliance filing was made on January 10, 2008.[276]

213. Although the evidence presented by Minnesota Power indicated that the Company has no general or default allocators,[277] based on evidence supplied by the Company, the OES concluded that:

> It appears that ALLETE specifically allocates certain costs to its non-regulated operations and subsidiaries, with any remaining costs left in MP's regulated operating division. This allocation method means that MP's regulated operations serve as the default for ALLETE's corporate costs. This process is not consistent

[271] *ITMO Minnesota Power's Asset Separation and Accounting Methodology,* Docket No E015M-01-1416 (*Asset Separation Docket)*.
[272] *Asset Separation Docket*, (Commission Order issued August 8, 2002) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=334257).
[273] *Asset Separation Docket*, Commission Order at 7.
[274] Ex. 25, DeVinck Rebuttal, at 4.
[275] *Id*.
[276] *ITMO the Petition of Minnesota Power for Approval of Asset Separation and Accounting Methodology*, Docket No. E015M-01-1416 (Compliance Filing made on January 10, 2008) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=4896495).
[277] Ex. 24, DeVinck Direct, at 5.

with Commission directives and precedent as detailed earlier, and may assign to MP's regulated operations a disproportionate share of ALLETE's costs.[278]

214. The OES thus has raised the issue of the Company using Minnesota Power as a default for allocating ALLETE's corporate costs. The Company denies doing that. The ALJ was unable to find sufficient detail in the prefiled testimony of either party to definitively resolve the issue one way or another,[279] and at the evidentiary hearing there was only perfunctory cross-examination of the witnesses with knowledge of that issue.[280] Unless Commission staff can establish from the record that the Company has, in fact, been using Minnesota Power as a default for allocation of ALLETE corporate costs, the ALJ recommends that the Commission approve the Company's corporate cost allocators, as proposed.

215. In any event, as the remedy for what the OES considers to be an unreasonable allocation of corporate costs, the OES is not recommending that the Commission require the Company to allocate corporate costs in this proceeding in a different way. Rather, the OES recommends that the Commission require Minnesota Power to legally separate its Minnesota regulated utility operations—Minnesota Power Company—from its parent company, ALLETE, by the time the Company files its next electric rate case, advancing three arguments to support that recommendation.[281] First, the OES believes that a legal separation provides a greater level of protection to ensure that ratepayers are not subsidizing any part of the parent company's unregulated activities. Second, it also believes that the creation of a holding company structure would provide a greater level of transparency to ALLETE's corporate costs allocations. Third, the OES argues that a legal separation would reduce the resources required to investigate any irregularities between the utility and non-utility entities.[282]

216. The ALJ disagrees with the OES recommendation of legal separation. Even if the Commission has the authority to require Minnesota Power to do business in a different legal form, the problem that the OES seeks to correct is a cost accounting problem that would not necessarily be resolved by legally separating Minnesota Power from ALLETE. The problem that the OES seeks to correct is ensuring that services exchanged between employees of the two entities are properly documented and accounted for using generally accepted accounting practices. Presumably, even if the two entities were legally separated, ALLETE employees would continue to perform work for Minnesota Power, and Company employees would continue to perform work for ALLETE; and issues of proper cost accounting are likely to remain.

[278] OES Brief, at 44 (citing Ex. 87A, Johnson Direct, at 9).
[279] Ex. 24, DeVinck Direct, at 3-8; Ex. 87A, Johnson Direct, at 7-9; Ex. 25, DeVinck Rebuttal, at 3-4; Ex. 88, Johnson Surrebuttal, at 2.
[280] Tr. Vol. 2, at 32, 36 (DeVinck); Tr. Vol. 5, at 65-67 (Johnson).
[281] OES Brief, at 44-45; Tr. Vol. 5, at 63 (Johnson).
[282] Ex. 87A, Johnson Direct, at 10.

## B. Amount of Allocated Corporate Expenses.

217. The Company estimated $89,526,995 for ALLETE's total corporate costs in the test year.[283] MP assigned $70,994,154 in ALLETE corporate costs to Minnesota Power in 2007. The Company has assigned $75,423,988 in ALLETE's corporate costs (84%) to Minnesota Power in the test-year. This represents $4,429,834 or an increase of 6.2% over the ALLETE corporate costs that were assigned to Minnesota Power in 2007.[284]

218. The OES contends that Minnesota Power has failed to establish that the increase in corporate costs proposed by MP for the test year is reasonable. In support of its contention, the OES points out that ALLETE's total corporate costs have generally been trending down from $96,002,471 in 2003 to $85,187,470 in 2007, and that the rate of inflation for the period July 2007 to July 2008 was 2.5 percent according to the most recent Consumer Price Index data from the U.S. Department of Labor Bureau of Labor Statistics.[285] The OES relied on the CPI because it excludes food and energy prices and because, historically, corporate costs do not include significant amounts of food and energy costs but consist primarily of wages and other corporate overhead.[286] OES therefore recommends that Minnesota Power recover $73,678,620 in the test year for corporate costs. That recommendation is based on allowing the Company to recover 2007 corporate costs adjusted by an annual inflation figure of 2.5 percent over 18 months. If approved by the Commission, this adjustment would result in a reduction to MP's corporate costs by $1,528,502 on a Minnesota jurisdictional basis.[287]

219. In response, Minnesota Power asserted that just under half of the $4.4 million increase in corporate costs is attributable to salary increases, while the balance is related to new staff and increased service costs for Information Technology, Project Engineering, Internal Audits, increased expenses for the Company's Conservation Improvement Program, and its membership in the Electric Power Research Institute (EPRI). The company supplied a table indicating the amounts by which each of those items was projected to increase.[288] MP also relied on the cross- and re-direct examination of OES's analyst, in which he accepted that the costs were being incurred for the purposes stated, that the Company would actually incur those costs during the test year, and that expenses of that kind would not only be incurred during the test year, but also going forward after the test year.[289] The Company also relied on the fact that OES was not disputing that new staff or IT, project engineering, and internal auditing services, or CIP, EPRI, and salary expenses were appropriate or prudent items to include in a test

[283] Ex. 87A, Johnson Direct, at 12.
[284] *Id.*
[285] Ex. 87A, Johnson Direct, at 13.
[286] *Id*.
[287] Tr. Vol 5 at 63 (Johnson); Ex. 87B, Johnson Direct Exhibits, MAJ-7; Ex. 111, Updated Lusti Financial Schedule, DLV-H-7.
[288] Ex. 25, DeVinck Rebuttal, at 5-6.
[289] Tr. Vol. 5, at 69-70, 78-79 (Johnson).

year.[290] In the absence of such challenges, MP asserts that it is unreasonable to make an adjustment to its proposed costs and that "these costs should not be rejected in favor of a theoretical expense amount that has never actually been experienced by the Company."[291]

220. As discussed above in the analysis of the test year, utilities typically use historical costs, adjusted by known and measurable changes, to arrive at the appropriate level of test year expenses. This method replaces the impact of market forces with "the fiscal discipline of prior determination of reasonable costs."[292] In this proceeding, there has been no "prior determination of reasonable costs" relied upon by MP. The kinds of costs that the Company relies on in projecting increases for the test year are the kinds of costs that MP has incurred in the past. The issue is not whether those kinds of costs are reasonable and prudent; the unanswered question is why the percentage increase of those costs that Company is projecting for the test year, is so much higher than in past years and why the Company expects that higher level of costs to continue throughout the life of the rate. Moreover, the Company has not explained why it has proposed budgets showing increased expenses at the same time it is forecasting reduced sales. In short, Minnesota Power has the burden of showing that any increases in cost from its most recent quantifiable expenses are justified and result in rates that are just and reasonable. As determined by statute, "Any doubt as to reasonableness should be resolved in favor of the consumer."[293] The ALJ concludes that Minnesota Power has not met that burden with regard to its projected increase of corporate costs from 2007 to the test year.

221. The OES has proposed a reduction to MP's corporate costs by $1,528,502 on a Minnesota jurisdictional basis.[294] That amount appears to be reasonable and consistent with Commission precedent. However, the Commission may wish to allow the Company to demonstrate specific changes in expenses that rise to the level of "known and measurable changes" prior to establishing a specific revenue deficiency upon which rates are set.

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[290] *See generally id*. at 67-71, 78-79.
[291] MP Brief, at 51 (citing *ITMO the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-05-1428, (Commission Findings of Fact, Conclusions of Law, and Order; Order Opening Investigation issued September 1, 2006)(rejecting proposed adjustments to filed test year data that did not "rise to the level of known and measurable changes")).
[292] *ITMO the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota*, Docket No. E002/OR-89-865 (Commission Order Denying Petitions for Reconsideration and Denying Transitional Rate Increase issued November 26, 1990).
[293] Minn. Stat. § 216B.03.
[294] Tr. Vol 5 at 63 (Johnson); Ex. 87B, Johnson Direct Exhibits, MAJ-7; Ex. 111, Updated Lusti Financial Schedule, DLV-H-7.

## X. E8760 ALLOCATOR.

222. Minnesota Power allocated energy costs using kWh sales for both a jurisdictional separation of costs and its class cost of service study ("CCOSS"), and it used the E8760 allocator to allocate energy costs among customer classes. The E8760 allocator takes into account the costs of energy based on the time of day the energy is used.[295] If a customer class consumes proportionately more of its energy during periods of peak demand when the market price for electricity is higher, the E8760 will assign that class its proportionate share of this high cost energy.[296] The Company described how it uses the E8760 allocator as follows:

> The E8760 is based on Minnesota Power's system Locational Marginal Price ("LMP") hourly cost and the hourly energy use of each class. It is derived by multiplying the hourly energy usage of each class by the system's LMP cost by hour, summing and taking the ratio of the sum of each class to the total. Applied as a cost allocator, the E8760 will yield class-specific responsibilities that take into account class use-patterns and time-variant system costs. In contrast to a straight non-weighted energy allocator, the E8760 results in a slight shift of class-specific responsibilities away from classes that take proportionately more of their energy during off-peak periods, to classes that take proportionately more of their energy during more expensive on-peak periods.[297]

223. The name E8760 reflects that there are 8760 hours in a year and that the different energy costs in each hour are used in developing a different energy factor for each customer class. MP indicates that its E8760 allocator is based on the methodology used by Xcel Energy in its CCOSS in a recent electric rate case (Docket No. E002/GR-05-1428).[298] The OES supports MP's use of the E8760 methodology for CCOSS purposes, stating that "[t]he OES agrees with the Company that using the energy allocator E8760 would allow the CCOSS to reflect class cost responsibilities more precisely since energy costs vary, sometimes significantly, from hour to hour."[299]

224. However, the OAG/RUD argues that the E8760 allocator is a poor method of determining costs in the CCOSS because: 1) MP used different allocators for other items, such a fuel costs; 2) LMP from 2007 does not reflect the LMP costs from the test year (2008-2009); 3) LMP pricing is a function of other utilities' cost of power, not just MP's cost; and 4) the

[295] MP Brief, at 84-85.
[296] Ex. 45, Shimmin Direct, at 1-2 and 8.
[297] Ex. 45, Shimmin Direct, at 8-9, Schedule 3.
[298] *Id*. at 8.
[299] Ex. 112, Ouanes Direct, at 9.

treatment of line losses in the E8760 allocator differs from MP's own reported costs through line losses.[300]

225. The OES responded to the OAG/RUD with a description of how the LMP is calculated. Based on that analysis, the OES concluded that using the E8760 energy allocation to assign energy costs is reasonable because the LMP is the market price that MP must pay for the energy provided to its customers.[301] Minnesota Power also produced a comparison between 2007 LMP prices and 2007 megawatt hours, showing an increase in the percentage of costs that the CCOSS would allocate to the residential and general service classes.[302] That comparison established that making adjustments to match costs of fuel to the LMP would decrease the assignment of costs to the Large Power class and would actually increase the share of the costs assigned to Residential and General Service classes.[303]

226. The ALJ concludes that the Company's use of the E8760 allocator is a reasonable method of allocating costs in the CCOSS and that the Commission should not require MP to use a different methodology for that purpose.

## XI. PROPOSED FCA MATCHING ADJUSTMENT.

227. As previously indicated, on July 21, 2008, the Commission entered an Order in Docket No. 08-463 that directed issues relating to a proposal by the Company to recover lagged fuel clause costs associated with the implementation of the new base cost of fuel, as well as associated changes to the Company's Rider for Fuel Adjustments to be addressed in this general rate proceeding.[304]

228. The essence of the Company's proposal was to change the lagged fuel cost adjustment to a forecast adjustment. Minnesota Power contemplated the change would be accomplished by providing it with a $19 million adjustment to account for the two and a half months that would drop out of the fuel clause calculation when the shift occurred from a lagged to a forecast adjustment. The OES and the LPI opposed the adjustment as unsupported in the FCA structure and not being of benefit to ratepayers.[305]

229. During the evidentiary hearing, MP, OES, Boise, MCC, and LPI reached agreement on the proposed FCA adjustment and other related billing issues. These parties entered into a

[300] Ex. 77, Lindell Surrebuttal, at 27-28.
[301] Ex. 113, Ouanes Rebuttal, at 6-7.
[302] Tr. Vol. 4, at 145-148 (Lindell); Ex. 49, Response to OAG/RUD IR 218, with attachments.
[303] *Id*.
[304] Commission Order Setting New Base Cost of Energy (issued July 21, 2008) at 2 https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5369014.
[305] Ex.. 67, Selecky Direct, at 26-31; Ex. 112, Ouanes Direct, at 14-17.

Stipulation under which MP agreed to withdraw the proposed FCA adjustment, subject to certain conditions, and also to withdraw the expedited billing and time-of-use billing proposals for Large Power customers that the Company had included in the rate petition. MP also agreed to initiate a tariff filing with the Commission to establish an FCA true-up mechanism to address over- and under-recovery of costs due to discrepancies between the monthly MWh charge when billed and the fuel cost actually incurred for that electricity.[306] However, neither the OAG/RUD nor the ECC were parties to the Stipulation, and the OAG/RUD objects to some of the Stipulation's terms as being contrary to the public interest.[307]

230. Despite the OAG/RUD's objections, the ALJ concludes that none of the Stipulation's terms are contrary to the public interest. The ALJ therefore recommends that the Commission accept the Stipulation and consider the Company's proposal to establish an FCA true-up mechanism when that tariff filing is made.

## XII. ECONOMIC DEVELOPMENT.

231. The OES supports recovery of Minnesota Power's economic development expenses, but only to the extent that those expenses are shown to be cost-effective by application of a "rate payer impact test" demonstrating that the Company's economic activities have a quantifiably favorable impact on its rates. The OES does not propose any quantitative rate payer impact test. Rather, it asserts that Minnesota Power bears the burden of developing such a test and demonstrating that the results of that test establish a favorable impact on customer rates. Finally, the OES argues that since Minnesota Power has failed to produce a reliable quantitative ratepayer testing methodology and therefore failed to establish which of its economic development activities have had a quantifiably favorable impact on its rates, all of its economic development costs should be disallowed.[308]

232. First of all, Minn. Statutes § 216B.16, subd. 13, provides:

> The Commission may allow a public utility to recover from ratepayers the expenses incurred for economic and community development.

In other words, the Legislature has given the Commission statutory discretion to allow a utility to recover economic development expenses in a rate proceeding.

233. The ALJ observes that economic development activities are like planting seeds. While some may grow to maturity and bear fruit in the form of new rate paying customers, others may fail to germinate. Even the economic development activities that do bear fruit may

[306] Ex. 107, Stipulation and Settlement Agreement.
[307] OAG/RUD Brief, at 55-57.
[308] Ex. 105, Davis Direct, at 5-7.

do so at different rates and over different time periods. In short, the impact of a utility's economic development activities on ratepayers does not lend itself to quantitative analysis. The Commission recognized this in its Otter Tail Power decision:

> As this Commission has previously concluded, any link between economic development expenditures and benefits to rate payers will of necessity be indirect. This indirect impact of necessity means that such costs are not easily translated into hard data analysis.[309]

234. The fact that the OES has not suggested a methodology for quantitative analysis of the financial impact of economic development activities on ratepayers is further evidence of its lack of susceptibility to quantitative analysis.

235. While no quantitative analysis of MP's economic development programs has been done, a significant portion of the public comment in this matter addressed that issue. The following are representative of the overall tenor of the comments received on this issue:

- The Northland Foundation urged support for MP's economic development programs as a key part of numerous beneficial programs for Northeastern Minnesota. Mark Lofthus, Director of Community Development for the Minnesota Department of Employment and Economic Development (DEED), noted that Minnesota Power has been an important part of DEED's efforts to market Northeastern Minnesota as a suitable location for business development.

- The Minnesota Community Development Fund (MCCF) supported MP's request for recovery of its economic development costs. MCCF noted that through MP's founding membership in MCCF, the Company has been instrumental in obtaining more than $10 million for northeastern and central Minnesota businesses—without risk to MP's ratepayers. Statewide, the Minnesota Community Capital Fund has already provided more than $30 million in loans to rural small businesses.

- Walt Prahl, President of Eventis/Hickory Tech, urged approval of MP's economic development costs due to MP's "very active and critical role in the economic development efforts within Northeastern Minnesota. Their efforts, along those of other corporate citizens in the community, have not only helped to attract new businesses to this region, but have also helped to increase

[309] *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, E-017/GR-07-1178 at 45. (Commission Findings of Fact, Conclusions of Law, and Order issued August 1, 2008) https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5408013.

vitality of existing businesses. From a rate payer perspective, this is important because with a more vibrant business economy there are more rate payers (more jobs = more employees = more rate payers), and more businesses that can share the fixed costs of electricity generation, transmission, and distribution. Ultimately these economic development efforts keep the costs to the rate payer lower than if the business environment is stagnant. I believe there is a direct linkage between growth in the regional economic base, the costs associated with affecting this growth, and the ability to keep electricity rates low going forward."

- Sansio (a Duluth-based software company) described the impact of MP's economic development programs on its own business and the opportunities for its employees. The Brainerd Lakes Area Development Corporation (BLADC) described the significance and importance of Minnesota Power's partnership in the region's economic development efforts, including financial support, sharing information, and fostering entrepreneurial development.

- The Hubbard County Regional Economic Development Commission (Hubbard County EDC) described its efforts with the Greater Minnesota Housing Fund, the Minnesota Housing Partnership, and the Minnesota Housing Finance Agency on a pilot/demonstration project to significantly reduce energy consumption and provide significant dollars for residential rehab efforts. Within the distressed neighborhood where this project was conducted, Minnesota Power provided energy audits to assist lower income customers an opportunity to reduce their energy costs. Hubbard County EDC supported recovery of MP's economic development costs to encourage this sort of participation in the future.

- Cirrus Design Corporation [the aircraft manufacturer] described how MP assisted in relocating Cirrus to Duluth, aided in its growth from 35 employees to over 1,200, and industry-related employment of over 4,400 full-time jobs. Brian Ryks, Executive Director for the Duluth Airport Authority, described how MP's efforts in economic development brought Cirrus Design to the area and resulted in a $1.3 billion economic impact in the area.

- Brian Graff, Vice President, Marketing & Public Relations, SMDC Health Systems, noted that Minnesota Power has been an effective leader on economic development issues (at times the sole effective leader) in many areas and has been a reliable partner and catalyst across the board. MP helped found Area Partnership for Economic Expansion (APEX), a partnership for improving business opportunities in Northeastern Minnesota. Don Monaco, Owner of

Monaco Air Duluth, Mark Hubbard, Sr. Vice President and Stephen A. Jones, Vice President for Lakehead Constructors, Inc., Dr. Kathleen L. Nelson, President of Lake Superior College, and David M. Gaddie, President/CEO of Republic Bank, also cited MP's role with APEX as important for economic development.

- Marlene Pospeck, Mayor of Hoyt Lakes, described MP's economic development programs as: "an extremely important element our in efforts to diversify the economy of the Iron Range. The company has partnered time and again with Iron Range Resources, a state agency, in providing financial incentives to businesses seeking to locate production facilities in northeastern Minnesota." Mayor Pospeck cited as examples the location of production facilities in Hoyt Lakes by Nott Company (formerly Belcorp) and Premier Plastics.

236. On the other hand, the assertion of the OES that a utility's economic development activities should also benefit its shareholders is a valid observation. In its Otter Tail Power decision, the Commission recognized the dual nature of potential benefits when it allowed that utility to recover 50% of its economic development expenditures.[310] Therefore, in the absence of a reliable quantitative method for apportioning the financial impact of Minnesota Power's economic development activities between ratepayers and shareholders, the ALJ recommends that the Commission apportion those expenditures equally between ratepayers and shareholders and allow Minnesota Power to recover 50% of those expenses in this rate proceeding.

## XIII. RATE CASE EXPENSES.

237. Minnesota Power originally proposed to recover $1,191,789 as rate case expenses, with none of those costs allocated to the non-regulated company, and to amortize those expenses on a three-year schedule;[311] it also proposes to include the unamortized balance of rate case expenses in the rate base.[312] Although the OES agreed with the amount that the Company had proposed as rate base expenses, the OES disagreed with the three-year amortization schedule and with including the unamortized balance of rate case expenses in the rate base; it also argued that a portion of the rate case expenses should be allocated to the non-regulated company.[313]

238. As previously discussed, selecting a reasonable amortization period for rate case expenses is important because ratepayers will continue to pay those costs in base rates until MP files its next rate case and may overpay significantly if MP fails to file its next rate case

[310] *Otter Tail Power 2008 Order*, at 48.
[311] Ex. 50, Podratz Direct, at 19.
[312] Ex. 52, Podratz Rebuttal, at 3-5.
[313] Ex. 103, Lusti Direct, at 8-10,14-19.

by the end of the amortization period. The amortization period should therefore represent as accurate a prediction as possible of the period of time that will elapse until the Company's next rate case.[314]

239. In support of its proposal to recover rate case expenses on a three-year amortization schedule, the Company asserts that it is "willing to put into a Commission order at the end of this case the requirement that the Company file another rate case on or before December 31, 2011."[315] The OES takes a more conservative approach to predicting an appropriate amortization period. It argues that while MP's current belief is that the Company will file a rate case in 3 years, many factors can impact the need for a utility to file a rate case, including but not limited to inflation, cost-of-money, the currently allowable rate of return, construction activity, and changes in the amount of customers' usage, along with accounting and policy changes.[316] The OES proposes a five-year amortization schedule for rate case expenses, arguing that it corresponds to the average period between rate cases that the Company has filed since 1976.[317]

240. The ALJ has previously recommended in this report that the Commission accept Minnesota Power's proposal to file another rate case within three years by directing the Company to do so. If the Commission accepts that recommendation, it should allow Minnesota to amortize rate case expenses on a three-year schedule. If the Commission does not accept that recommendation, it should follow the OES's recommendation and direct the Company to amortize those costs on a five-year schedule.

241. The OES argues that the fact that ALLETE includes not only Minnesota Power but also several non-regulated operations complicates regulatory review. Because of the Company's non-regulated activities, the OES contends regulatory assessments of its rate proposal necessarily include considerable time devoted to issues of allocating costs and revenues between the utility and non-regulated operations. For example, if ALLETE did not have non-regulated activities, there would be no need for corporate cost allocations. Therefore, the OES contends that it is reasonable for the Company to also allocate to non-regulated activities a portion of the regulatory assessment costs, as well as the Company costs.[318] The OES further argues that it had recommended and the Commission had approved an allocation of rate case expenses to the non-regulated activities in at least nine previous case proceedings.[319] The OES therefore recommends an allocation of 5.76 percent of the rate case costs, or $68,647, to the non-regulated operations of Minnesota Power.[320] The OES arrived at that percentage

[314] MP Brief, at 50.
[315] Tr. Vol. 1, at 33 (McMillan).
[316] OES Brief, at 37.
[317] Ex. 103, Lusti Direct, at 16-17
[318] Ex. 104, Lusti Surrebuttal, at 3.
[319] *Id*.
[320] Ex. 103, Lusti Direct, at 15; and see Ex. 104, Lusti Direct Exhibits, Attachment DVL-9, Schedule 2.

by dividing the Company's test-year non-regulated corporate support services costs by the sum of its test-year regulated and non-regulated corporate services costs.[321]

242. In response, Minnesota Power accepts in principle the proposition that some rate case expenses should be allocated to non-regulated activities, but disagrees with the amount that the OES is proposing to allocate.[322] Although the Company agrees that 5.76% of certain rate case expenses may be allocated to non-regulated activities, it maintains that regulatory assessments are expenses that should not be included in that allocation.[323] It therefore proposes an adjustment of $34,087, which it computes by calculating 5.76% of $1,191,789 less $600,000 in regulatory assessments for total allocable expenses of $591,789.[324] The net effect of Minnesota Power's approach is to reduce the amount of allocable rate case expenses to 2.86 percent of the total rate case expenses.[325] The Company argues that a lower adjustment is warranted because "it is not logical to allocate any portion of the regulatory assessment (the costs of the Commission and the OES) to the non-regulated activities of Minnesota Power."[326]

243. The OES's decision to include all rate case expenses in its analysis has a rational basis. There appears to be no discernable reason for excluding regulatory assessment from the total. Computing the allocation percentage by dividing the Company's test-year non-regulated corporate support services costs by the sum of its test-year regulated and non-regulated corporate services costs also has a rational basis. It appears to the ALJ that what the Company appears to consider illogical is prescribing an allocation percentage of 5.76 percent in the proceeding in comparison with the 0.35 percent allocation percentage that the Commission approved in 1994. However, the Company offers no insight into the Commission's reasoning for approving a lower allocation percentage in 1994. Any number of things may have entered into the Commission's 1994 decision. In the absence of a reasoned explanation of why a lower allocation percentage was approved in the earlier proceeding, the ALJ recommends that the Commission accept the OES's analysis and approve an allocation of 5.76% of $1,191,789 in rate case expenses to non-regulated activities.

244. Finally, like the Company's proposal regarding unamortized deferred MISO 16 and 17 costs,[327] the Company also seeks to include unamortized rate case expenses in the rate base.[328] Again, the Company contends that because those costs originate as an expense, the delay between payment and recovery warrants treating the unamortized rate case expenses as an investment, like other kinds of prepaid expenses. The Company

[321] *Id.*
[322] Ex. 53, Podratz Rebuttal, at 3-4, MAP Schedule 1.
[323] *Id.*
[324] *Id.*
[325] Ex. 53, Podratz Rebuttal, at 3.
[326] MP Brief, at 49.
[327] See Findings 158-161.
[328] Ex. 52, Podratz Rebuttal, at 3-5.

therefore argues that its shareholders should be able to earn a return on the amounts not paid in the test year. Moreover, in further support of rate base treatment of unamortized rate base expenses, Minnesota Power cites the fact that the Commission approved a three-year amortization of rate case expenses, including the unamortized balance in the rate base in Company's 1994 rate case.[329] Minnesota Power requests the identical treatment of rate case expenses in this case.[330]

245. In response, the OES argues against rate base treatment of unamortized rate case expenses for the same reasons it argued against rate base treatment of deferred MISO Schedule 16 and 17 costs. The OES asserts that the Company's proposal to place those costs in the rate base is inconsistent with ratemaking principles in that returns are generally allowed only for capital costs, and that rate case expenses and should be treated as traditional expenses are treated, without a return. Additionally, the OES notes that since the Company's 1994 rate case, the Commission has consistently denied recovery of rate case expenses in rate base in twelve more recent rate cases.[331]

246. It appears to the ALJ that the Commission has adopted another policy about rate base treatment of rate expenses since the Company's 1994 rate case. Like legislatures, past Commissions cannot bind the action of future Commissions, and in this case the Commission has given utilities thirteen years' notice of its change in policy. The ALJ therefore recommends that the Commission not allow the Company to recover unamortized rate case expenses in its rate base.

## XIV. RATE BASE.

### A. Agreed-upon Adjustments to Rate Base.

247. In setting rates for a public utility, the Commission must determine the total level of investment by the utility in its "utility property used and useful in rendering service to the public."[332] In utility rate cases, those investments are referred to as the utility's rate base. MP's initially filed revenue requirement of $45,023,320 included a proposed rate base of $713,096,651.[333] The OES and MP have agreed on the following adjustments to the rate base as initially filed:

- Cash Working Capital Methodology; calculated by applying the OES's lead/lag days to the OES O&M expense adjustments; results in a decrease to the test-year cash working capital requirement by $648,863 (This particular amount assumes Commission approval of

[329] *MP 1994 Rate Order*, at 37.
[330] Ex. 52, at 3-5.
[331] OES Brief, at 32.
[332] Minn. Stat. § 216B.16, subd. 6.
[333] Ex. 1, Notice of Change in Rates and Supporting Schedules, MAP Revised Schedule A-4, 5/22/08.

all OES proposed adjustments; otherwise the amount will need to be recalculated).[334]

- Hibbard Energy Center; increase test-year rate base by $46,364.[335]

- BPUC Transmission Asset Sale; decrease test-year rate base by $228,420.[336]

- Badoura Pine River Surface Project; decrease test-year rate base by $3,913,595.[337]

- Mesabi Nugget Service Extension; increase test-year rate base by $1,120,378.[338]

- Taconite Ridge Wind Project; increase test-year rate base by $825,327.[339]

- Customer Advances and Deposits; decrease test-year rate base by $2,526,812.[340]

- Deferred Taxes; decrease test-year rate base by $6,198,049.[341]

- BEC-4 Boiler Project; decrease test-year rate base by $323,922.[342]

- E015/D-08-422 Depreciation Expense; decrease test-year rate base by $2,186,066.[343]

248. The agreed-upon adjustments to the rate base are reasonable and should be approved by the Commission.

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334 Ex. 111, Updated Lusti Financial Schedule, Attachment DVL-H-5, Schedule 1.
335 Ex. 87B, Johnson Direct Exhibits, Attachment MAJ-13; Tr. Vol. 5, at 62 (Johnson); and MP Ex. 54, Podratz Rebuttal Revisions, MAP Schedule 17.
336 Ex. 87B, Johnson Direct Exhibits, Attachment MAJ-19 Tr. Vol. 5, at 62 (Johnson); and MP Ex. 54, Podratz Rebuttal Revisions, MAP Schedule 17.
337 Ex. 104, Lusti Surrebuttal, at 20-21, Attachment DVL-S-4; and Ex. 54, Podratz Rebuttal Revisions, MAP Schedule 17.
338 Ex. 104, Lusti Surrebuttal, at 22, Attachment DVL-S-4; and Ex. 54, Podratz Rebuttal Revisions, MAP Schedule 17.
339 Ex. 104, Lusti Surrebuttal, at 22, Attachment DVL-S-4; and Ex. 54, Podratz Rebuttal Revisions, MAP Schedule 17.
340 Ex. 104, Lusti Surrebuttal, at 23, Attachment DVL-S-4; and Ex. 54, Podratz Rebuttal Revisions, MAP Schedule 17.
341 Ex. 104, Lusti Surrebuttal, at 23, Attachment DVL-S-4; and Ex. 54, Podratz Rebuttal Revisions, MAP Schedule 17.
342 Ex. 104, Lusti Surrebuttal, at 21-22, Attachment DVL-S-4; and Ex. 54, Podratz Rebuttal Revisions, MAP Schedule 17.
343 Ex. 111, Updated Lusti Financial Schedule, Attachment DVL-H-4, Column (n); and Tr. Vol. 5, at 62 (Johnson).

### B. Rate Base Treatment for Deferred Rate Case Expenses.

249. MP proposed inclusion of the deferred portion of rate case expenses in the rate base. The OES objected to this proposal as inappropriate. As discussed in the general treatment of rate case expenses, the ALJ recommends that MP not be allowed to include these deferred expensed in the rate base.[344]

### C. Rate Base Treatment for Deferred MISO Schedule 16 and 17 Costs.

250. MP proposed inclusion of the deferred portion of MISO Schedule 16 and 17 costs in the rate base. The OES objected to this proposal as inappropriate. As discussed in the general treatment of deferred MISO Schedule 16 and 17 costs, the ALJ recommends that MP not be allowed to included these deferred expensed in the rate base.[345]

### D. Asset Retirement Obligation Depreciation Methodology.

251. The concept of "decommissioning" involves the assumption that a generation facility will eventually reach the end of its service life and will have to be shut down and replaced. However, in practice decommissioning rarely occurs. The parties have cited no example of a Minnesota electric utility decommissioning a generation facility, and it is unlikely that any sites will be decommissioned in the near future because since they are too valuable to both ratepayers and shareholders.[346] Nevertheless, if a generation facility were shut down, it is likely that the utility would incur costs in removing it. When those costs become so high that the removal cost is more than the plant is worth, the generation facility will have a negative, rather than positive, salvage value.

252. Although decommissioning may be rare, the Commission allows electric utilities to incorporate the possibility of decommissioning plants into their rates by allowing them to recover costs associated with decommissioning over time. In the past, the Commission has consistently approved a cost-based method for accounting for decommissioning expenses and net salvage value. That method (the Decommissioning Method) involves estimating the plant's negative salvage value at the end of the plant's service life and then amortizing that negative salvage value, along with associated decommissioning expenses, on a straight line schedule over the plant's service life.[347] The asset retirement obligation approach (the ARO Method) accounts for asset retirement costs somewhat differently. It is based on market value, and asset retirement costs are amortized on an accelerated schedule over the plant's estimated service life.[348] Thus, under the ARO method, ratepayers receiving service from the asset at the beginning of

[344] *See* Findings 245-247, *supra*.
[345] *See* Findings 158-161, *supra*.
[346] Ex. 95A, Campbell Direct, at 39.
[347] Ex. 96, Campbell Surrebuttal, at 27-28.
[348] Ex. 95A, Campbell Direct, at 36-37.

its service life pay asset retirement costs that are greater than ratepayers receiving service at the end of its service life.[349]

253. Generally accepted financial accounting standards recognize both the Decommissioning Method and the ARO Method as acceptable accounting methods. However, in an Order dated July 11, 2003, the Commission placed the following conditions on Minnesota Power's use of the ARO method in future retail rate cases:

> The Commission will accept MP's accounting for adoption of FASB 143 and the resulting regulatory asset, with the ultimate issue of rate recovery to be determined in MP's next rate case proceeding. *Additionally, regarding future rate recovery of this regulatory asset MP will be required to show that the ARO accounting method is a superior method for purposes of rate recovery over the current salvage value method.* Although the Commission recognizes the importance of FASB 143 to provide consistent accounting for asset retirement obligations in Company's financials, this function does not necessarily require a change in our current rate recovery method for salvage/decommissioning costs in future rate cases.[350] [Emphasis supplied.]

254. In this rate case, Minnesota Power seeks to recover asset retirement costs for its generation plants using the ARO accounting method. At the outset of this proceeding, the Company included a total of $3.5 million in asset retirement obligations in the test year.[351] The Company subsequently reduced that amount by $826,211 because previously approved negative net salvage value had been included in both the ARO amount of $3,507,674 and in its depreciation expense amount for purposes of this rate case. Therefore, the amount that the Company is now seeking to include in the test year for asset retirement obligations is $2,681,463.[352] But the issue in this rate case is not whether the Company's ARO method is an acceptable accounting method. Rather, as the Commission previously directed, it is whether MP has shown ARO to be superior to the net salvage value method and therefore, whether it is a reasonable accounting method in this proceeding for ratemaking purposes.

255. Minnesota Power advances three arguments in support of superiority of the ARO Method over the Decommissioning Method:

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[349] *Id*.
[350] *ITMO Minnesota Power's Request for Approval of the Remaining Life Depreciation Study for 2003*, Docket No. E-015/D-03-560, at 4 (Commission Order Certifying Depreciation Rates and Methods issued July 11, 2003)(*MP Depreciation 2003 Order*).
[351] Ex. 95A, Campbell Direct, at 32- 33.
[352] Ex. 102, Campbell Testimony Summary, at 3.

> (i) The ARO Method was developed, vetted and adopted by two sophisticated accounting rule setting authorities, namely the FERC and the Financial Accounting Standards Board;
>
> (ii) The ARO Method is a more systematic and ratable method of allocating asset retirement costs over the life of the asset. Under the Decommissioning Method, more asset retirement expense is recognized near the end of an asset's life, thereby placing a disproportionate burden on future ratepayers; and
>
> (iii) Perhaps most importantly, the FERC approved Minnesota Power's ARO method in the Company's most recent wholesale rate case.[353]

256. The Company also argues that the ARO Method is superior because it is measured at fair value while the Decommissioning Cost Obligation is measured at current cost, without taking into account the impact of inflation when the obligation is ultimately settled in future years.[354]

257. First, as the OES and the LPI point out, the effect of Statement of Financial Standards ("SFAS," also called "FASB") 143 is to establish the ARO Method as an *acceptable* way of accounting for the future decommissioning of a generating plant in retail rate cases; it does not purport to establish the ARO Method as superior to the Decommissioning Method for that purpose.[355] That is the way the Commission regards FASB 143.[356]

258. Second, like FASB 143, FERC Order 631 does no more than prescribe accounting standards whenever a utility happens to use the ARO Method. In fact, FERC Order 631 expressly states that it does not purport to establish the ARO Method as superior to the Decommissioning Method for the purpose of setting retail rates, and it expressly does not require the Commission to adopt the ARO method for that purpose:

> The Commission [FERC] will decline to make policy calls concerning regulatory certainty for disposition of transition costs, external funds for amounts collected in rates for asset retirement obligations, adjustments to book depreciation rates, and the exclusion of accumulated depreciation and accretion for asset retirement obligations from rate base; these are matters that are not subject to a one size fits all approach and are better resolved on a case-by-case basis in rate proceedings. *The Commission is of the view that utilities will have the opportunity to seek recovery of qualified costs for asset retirement obligations in individual rate*

[353] DeVinck Direct, at 14-15; DeVinck Rebuttal, at 7-11.
[354] DeVinck Direct, at 15.
[355] Ex. 95A, Campbell Direct, at 34.
[356] See *MP Depreciation 2003 Order*, at 4.

*proceedings. This rule should not be construed as pregranted authority for rate recovery in a rate proceeding*.[357] [Emphasis supplied.]

259. Accordingly, FERC approval of Minnesota Power's use of the ARO Method in its most recent wholesale rate case does not establish that it is superior to the Decommissioning Method in this retail rate case.[358]

260. Third, the ALJ agrees with the OES, LPI, and AGO/RUD that the ARO Method is not substantively superior to the Decommissioning Method and therefore more reasonable for retail ratepayers. First, Minnesota Power argues that by correlating cost recovery to the declining value of generation assets, the ARO Method provides a better matching of cost with the ratepayers who receive the benefits.[359] However, the ALJ is unable to discern any intrinsic societal value that would be adversely affected by having future ratepayers pay a share of decommissioning costs that was disproportionate to the depreciated value of the asset providing them with electrical service.

261. The Company also argues that the ARO Method more accurately reflects the retirement obligation and related annual expense because they are measured at fair value while the Decommissioning Cost Obligation measures them at current cost. It argues that the Decommissioning Method therefore does not take into account the impact of inflation when the obligation is ultimately settled in future years.[360] But as the OES correctly observes, by allowing the Company to recover those costs well in advance of the end of a generating plant's service life, it provides the Company with funds to cover future decommissioning costs, thus allowing the Company to receive the time value of money. On the other hand, looking at the time value of money from the ratepayers' perspective, the ARO Method appears to confer an additional economic benefit to future ratepayers that current ratepayers will not receive, since an accelerated amortization schedule appears to distort the principle of time value of money to a greater degree than a straight line amortization schedule.

262. After considering the Company's arguments, the ALJ concludes that, in theory, the ARO Method appears to be neither superior nor inferior to the Decommissioning Method and, on that basis alone, appears to fail the test that the Commission established on July 11, 2003. However, as the OES observed, the ARO Method in practice is actually inferior to the Decommissioning Method from the standpoint of its economic impact on ratepayers. In theory, the total costs recovered under the Decommissioning Method and the ARO Method would be the same.[361] The accelerated nature of ARO means that the amount of depreciation/decommissioning expense at the beginning of an asset's life

[357] FERC Order 631 of April 9, 2003, in Docket No. RM02-7-000 at 29-30.
[358] FERC Docket ER08-397-000, Feb. 8, 2008 Letter Order.
[359] Ex. 25, DeVinck Rebuttal, at 8.
[360] Ex. 24, DeVinck Direct, at 15.
[361] *See* Ex. 25, DeVinck Rebuttal, Schedule 3.

is by definition too high for use in later years when it should be greatly decreased. However, since the depreciation/decommissioning amount is fixed in base rates at the time of a rate case, that amount will continue in rates until the next rate case. Therefore, if ARO were allowed for ratemaking, that "too high" amount will be fixed in rates, and will continue in rates until the utility files its next rate case.[362]

263. Put another way, with straight line amortization, there is no possibility that the decommissioning costs established for the test year will be unrepresentative of the costs recovered in subsequent years throughout the life of the rate. However, that is not the case with the ARO Method, since the costs assigned to the test year will have the effect of creating a "step" during the life of the rate that would exceed what the normal ARO amortization schedule would specify for subsequent year under that rate. The ALJ therefore concludes that the Commission should not approve Minnesota Power's proposal to use the ARO Method, rather than the Decommissioning Method, for recovery of the future costs of decommissioning its generation facilities, and that appropriate adjustments be made to its test year and rate proposal.

**E. Non-Rate-Based Generators.**

264. Minnesota Power operates two generation facilities, with a combined output of 50 MW, that are not currently included in its rate base—the Rapids Energy Center ("REC") adjacent to the Blandin paper mill in Grand Rapids and the Sappi/Cloquet Generator No. 5 at the Cloquet Energy Center ("S/C5") adjacent to the Sappi paper mill. The Company acquired the two generation facilities after its most recent general rate case had concluded in 1994, and this proceeding is the Commission's first opportunity to determine whether both facilities, or either of them, should be included in Minnesota Power's rate base. Minnesota Power excludes the revenues and costs from these two generation facilities from its operating income.[363]

265. After UPM-Kymmene (UPM or Blandin) purchased Blandin Paper's operations in Grand Rapids, UPM sought a strategic realignment with Minnesota Power of the steam supply for the Grand Rapids mill. Thereafter, UPM Grand Rapids approached Minnesota Power about assuming ownership of and operating UPM's on-site hydro and steam generation unit.[364] In March 2000, Minnesota Power purchased Blandin's No. 6 and No. 7 turbine generators (each having an approximately 16 MW nameplate rating); two wood/coal fired boilers; accompanying infrastructure and buildings; and a 1 MW run-of-river hydro facility located at Blandin's lightweight coated paper production site. Minnesota Power subsequently added two gas-fired natural gas boilers to the site as part of the agreement.[365]

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[362] Ex. 96, Campbell Surrebuttal, at 28-29.
[363] Ex. 24, DeVinck Direct, at 5.
[364] *Id*.
[365] Ex. 29, Norberg Rebuttal, at 16.

266. Under the terms of the parties' Steam Service, Operation and Support Agreement, which the Commission previously approved, the REC is dedicated to one customer— Blandin Paper. For a set price, Minnesota Power provides all the steam for Blandin's paper making, as well as an amount of power for paper production equivalent to that produced by the on-site generation units.[366] For the most part, the relationship between the REC and the Blandin mill physical plants is such that most of the electricity generated by the REC can only be produced when the mill is making paper. There is, however, some ability of the REC to generate a small amount of electricity when the paper mill is not running and when the Blandin production process does not need it.[367]

267. Section 6 of the Steam Service, Operation and Support Agreement between MP and Blandin provides that if the parties do not reach an agreement by March 2010 to extend the current cogeneration agreement or have Blandin purchase back the cogeneration facilities at the production site, then Minnesota Power will remove the facilities consistent with the terms of its site lease with Blandin. Minnesota Power and Blandin are currently engaged in discussions regarding whether their cogeneration agreement should be extended past 2010 or whether Blandin should purchase back some or all of the cogeneration facilities.

268. The record therefore establishes that UPM currently has a contingent property interest in the REC that is likely to be either perfected or extinguished on or before March 2010. As previously, discussed, The ALJ has recommended that the Commission order the Company to file another rate case by December 2011.[368] Because of the possibility that the REC will no longer be owned by Minnesota Power in December 2011, or even exist, the Commission should delay consideration of the inclusion of REC into the rate base until Minnesota Power's next rate case.

269. In 2000, Minnesota Power entered into an agreement with Sappi (formerly Potlach), another paper mill operator, under which Minnesota Power installed a 25 MW turbine generator at Sappi's Cloquet Mill site (Sappi 5).[369] Under that agreement, Minnesota Power retains its ownership interest in the turbine generator while Sappi owns the boilers and other infrastructure needed for the generation of electricity at the Sappi 5 site.[370] The agreement also provides that Minnesota Power must pay for the fuel and O&M related to operation of Sappi 5 and must also make a monthly Infrastructure Payment to Sappi for using Sappi's boilers and infrastructure to produce the steam used to generate electricity. The electricity produced using Sappi 5 is not dedicated to Sappi, but rather is available to meet the needs of all Minnesota Power's retail customers. The parties' agreement also provides that in May 2016 Sappi has the right to purchase the turbine

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[366] Ex. 29, Norberg Rebuttal, at 16.
[367] *Id*. at 16-17; Tr. Vol. 2 at 62-63 (Norberg).
[368] *See* Finding 157, *supra*.
[369] Ex. 95A, Campbell Direct, at 41-42.
[370] Ex. 29, Norberg Rebuttal, at 18.

generator from Minnesota Power for $1.[371] Since the power produced at Sappi 5 is not dedicated to Sappi's Cloquet mill, Sappi obtains the electrical power needed to operate that mill from Minnesota Power's general retail distribution system, like any other retail customer.[372]

270. The OES argues that both the REC and the Sappi 5 generation facilities should be placed in Minnesota Power's rate base in this proceeding and cites five reasons. First, since even the Blandin mill is a retail customer, both facilities are used to serve the Company's retail customers. Second, the generation from both is included in the most recent Mid-Continent Area Power Pool Load and Capability Report.[373] Third, the Company included generation from the two facilities in its 2004 Integrated Resource Plan (IRP) as generation required to serve retail customers.[374] Fourth, MP counts these generators towards its Renewable Energy Standards and in the Midwest Renewable Energy Tracking System; and fifth, the generators are owned by Minnesota Power, the regulated utility. In the ALJ's view, apart from considerations of administrative consistency, whether the REC and Sappi 5 facilities should be included in the Company's rate base at this time turns on the answers to two questions: (1) to what extent are the two facilities dedicated cogeneration facilities? and (2) to what extent would rate base treatment at this time interfere with the contractual rights of third parties?

271. There are material differences in function and status between the REC and the Sappi 5 generation facilities. The REC and the Blandin mill are physically codependent; the REC can generate electricity only when the mill is making paper. Blandin has a contractual right to all of the output of REC and normally does use all of REC's output. The energy that Minnesota Power's other retail customers obtain from that facility is, at best, minimal and sporadic. Moreover, the REC not only provides the Blandin mill with electric energy, it also provides the mill with steam necessary for the papermaking process. Finally, if not exercised, UPN's contingent contract right to regain ownership of the REC expires in March 2010—that is, the ownership status of the REC will be resolved before Minnesota Power files its next rate case. In short, the REC generation facility represents a true cogeneration facility, and placing it in the Company's rate base now could result in legal complications. It therefore makes sense to wait until Minnesota Power's next rate case to determine whether that facility, if still owned by the Company, should be placed in the rate base.

272. The Sappi 5 generation facility's situation is materially different. Its output does not go directly to Sappi's Cloquet mill, and it is therefore not physically a cogeneration facility. Rather, all of Sappi 5's output goes into Minnesota Power's retail distribution system and is therefore available to all of the Company's retail customers. Conversely, Sappi

[371] *Id*. at 18-19.
[372] Tr. Vol. 2, at 99-100 (Norberg).
[373] Ex. 95B, Campbell Direct Exhibits, NAC-17.
[374] *Id*. NAC-18.

obtains all of the electrical power needed to operate its Cloquet mill from Minnesota Power's retail distribution system, like other retail customers. It was Minnesota Power that supplied the turbine and has operated the Sappi 5 facility since it was constructed. Although Sappi owns the property on which the facility was constructed and some of the infrastructure, it has never been directly involved in its operation. Sappi also possesses an option to purchase the facility that is exercisable in 2016, but that will not occur before Minnesota Power files its next rate case. Unlike REC, there is no evidence that Sappi is currently involved in negotiations regarding exercising its contractual right to purchase the facility, and if Sappi indicates an intent purchase it in 2016, there would have to be a proceeding before the Commission during which removal of Sappi 5 from the rate base could also be considered. The ALJ therefore concludes that, unlike the REC, the Sappi 5 facility should be accorded rate base treatment now.

273. If the Commission were to place either the REC or Sappi 5 facility, or both, into the rate base in this proceeding, the corresponding revenues, depreciation, and O&M expenses for the facilities associated with them must be recognized at the appropriate level. With regard to revenues, the OES recommends that a pro rata share of total system revenues should be assigned to the facilities on the basis of megawatts produced. On the other hand, Minnesota Power argues that the Commission should accept the facility-specific budget revenue estimates for the test year that the Company produced for each of the two facilities. Neither the OES nor any other party raised specific criticisms of the reliability of the facility-specific revenue estimates that the Company made for the REC and Sappi 5 facilities. In the absence of such criticisms, the Commission should accept Minnesota Power's facility-specific estimates rather than the OES's more general allocation based on system-wide averages.

274. On the other hand, the OES does take issue with some of the expenses that Minnesota Power proposes to allocate to those two facilities—specifically, depreciation and O&M expenses. In its direct testimony, the OES expressed concern that the Company's composite depreciation rates of 11.76% and 9.64% appear to be based on depreciation lives that were unreasonably short, and it recommended that the Company address this depreciation life issue in their reply comments.[375]

275. Minnesota Power indicated that depreciation for the REC was based on a March 2010 termination date, and that Sappi 5 was based on a May 2016 termination date, the dates on which the respective contracts with UPN and Sappi expire. In response, the OES pointed out that the life of the underlying contracts did not bear any necessary relationship with the service lives of those assets, and OES continues to object to the Company's depreciation expense for the REC and Sappi 5 facilities.[376] Minnesota Power has never come forward with proposed depreciation expenses for the two facilities for the test year based on reasonable estimates of their service lives. The ALJ

[375] Ex. 95A, Campbell Direct, at 36.
[376] Ex. 28, Norberg Rebuttal, at 19; Ex. 96, Campbell Surrebuttal, at 36-37.

therefore suggests that there are three options available to the Commission: (1) deny any depreciation expense for REC or Sappi 5 to the extent that either is included in the rate base; (2) allow depreciation expense based on the average service life of Minnesota Power's other generation facilities; or (3) provide the Company with the opportunity to come forward with reasonable estimates of the service lives of either or both of the facilities with appropriate documentation.

276. With regard to the O&M expenses associated with the REC and Sappi 5 facilities, the OES also believed that $17.1 million in O&M expenses that Minnesota Power allocated to the two facilities in the test year were unreasonably high and unsupported. Similar to its recommendation for revenues, the OES therefore proposed to assign a pro rata share of total system O&M expenses to the facilities on the basis of their respective capacities in megawatts.[377] In rebuttal testimony, the Company came forward with a more specific listing of the O&M expenses that it had budgeted for the two facilities for the test year.[378] In its surrebuttal, the OES still expressed concern that in the aggregate, the O&M costs of the REC and Sappi 5 were nearly four times higher than their pro rata shares of system wide O&M costs.[379]

277. During the hearing, Minnesota Power provided the other parties with detailed listings of its projected test year O&M expenses for the REC and Sappi 5 facilities, together with comparisons with the actual O&M expenses for the two facilities in 2006 and 2007.[380] More specifically, the Company provided that information off the record to the other parties after the hearing recessed on Monday, November 17, 2008. It subsequently introduced that information into the hearing record as Exhibit 101 on Wednesday, November 19th, the next to the last day of the hearing.[381] Although that exhibit contains detailed information on the Company's proposed test year costs for the REC and Sappi 5 in comparison with the actual O&M costs for 2006 and 2007, there was relatively little time for other parties to analyze the additional data contained in that exhibit, and the hearing record therefore contains little testimony or further information about its contents.

278. Nonetheless, that data raises some significant issues that need to be resolved. Exhibit 101 indicates that certain O&M expenses for the Sappi 5 facility, which the Company aggregates as "Miscellaneous Expenses" in 2006 and 2007, are shown to increase about 16% from 2006 to 2007 and, again, from 2007 to the test year, and there is no explanation of what accounts for those rather large annual increases. The O&M expenses for the REC increased about 2% from 2006 to 2007 but about 8½% from 2007 to the test year. While many of the test year O&M expenses appear reasonable in comparison with 2006 and 2007, at least two categories show unusually high and

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[377] Ex. 95A, Campbell Direct, at 49-50.
[378] Ex. 53, Podratz Rebuttal, at 12 and Schedule 5.
[379] Ex. 96, Campbell Surrebuttal, at 36-38.
[380] Ex. 101, REC/CEC O&M Expenses.
[381] Tr. Vol. 5 at 110-112.

unexplained increases in comparison with the actual expenses for 2007—namely, Salaries and Wages (9%) and Contract Services (63%). Those two expense items alone represent $1,032,577 in increased test year costs for the REC. Lacking reasonable explanations, the ALJ cannot conclude that Minnesota Power has demonstrated that its proposed test year O&M expenses for the REC and Sappi 5 facilities are reasonable. Again, the ALJ suggests that there are three options available to the Commission: (1) deny any test year O&M expenses for whichever of the two facilities is included in the rate base; (2) allow O&M expenses based on allocating each a pro rata share of system wide O&M costs; or (3) provide the Company with an opportunity to come forward to demonstrate reasonable bases for those costs.

279. Minnesota Power opposes putting either the REC or S/C5 into rate base. In the event they are placed into the rate base, the Company argues that the revenues for the facilities must be facility-specific budgeted revenues documented by MP in is testimony and schedules.[382] On the other hand, the OES argues that the assigned revenues should be based on system wide average revenues per MWh multiplied by the number of MWh generated by each of the generators in question.[383] However, unlike the Company's projected O&M expenses, the OES cites no reason for questioning the accuracy of MP's facility-specific revenue estimates. Lacking support or a reason to reject the actual revenue figures, the ALJ concludes that the Commission should accept Minnesota Power's facility-specific revenue estimates.

## XV. RATE DESIGN.

### A. Class Revenue Apportionment.

280. When setting rates, the Commission is responsible, in part, for determining how much each customer class should contribute to meeting the utility's revenue requirement. In making that determination, the Commission considers the following factors:

> The Commission requires utilities to file a CCOSS because the cost a utility incurs to provide service is one factor the Commission considers in determining how much each customer class should contribute to meeting the utility's revenue requirement, and how to recover each class' share of the revenue requirement from the members of the class. Other factors include economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation, ability to pay; and ability to bear, deflect or otherwise compensate for additional costs.[384]

[382] Ex. 53, Podratz Rebuttal, at 12.
[383] Ex. 95A, Campbell Direct, at 51; Ex. 96, Campbell Surrebuttal, at 38.
[384] *ITMO the Application of CenterPoint Energy Minnesota Gas, a Division of CenterPoint Energy Resources Corp., for Authority to Increase Natural Gas Rates in Minnesota*, PUC Docket No. G-008/GR-05-1380, at 38 (Commission Findings of Fact. Conclusions of Law, and Order issued November 2, 2006)

281. Minnesota Power apportioned its total revenue responsibilities among rate classes based on its CCOSS and its rate design objectives, which included cost based rates, maintaining reasonable rate continuity, mitigating rate shock, and encouraging the efficient use of resources. The Company proposed the following allocations among customer classes:

(https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3560745) (*CenterPoint Energy 2006 Order)*.

| Class Revenue Responsibility — Proposed Increase by Class[385] | | | | | | |
|---|---|---|---|---|---|---|
| Customer Class | | Increase by Class (as originally proposed) | Class Responsibility for Percent of Total Revenue | Percent Increase in Revenue | | Percent Revenue Responsibility Differs from Cost Responsibility |
| Residential | | $17,041,158 | 17.4% | 23.8% | | -12.3% |
| General Service | | 10,281,072 | 10.8% | 23.0% | | -1.4% |
| Large Light and Power | | 4,527,801 | 13.9% | 6.8% | | -0.1% |
| Large Power | | 21,324,514 | 56.4% | 4.5% | | 4.3% |
| Municipal Pumping | | 803,775 | 0.9% | 20.1% | | 24.6% |
| Lighting | | -0- | 0.5% | 0.0% | | 35.7% |
| | | | | | | |
| Totals | | $44,978,320 | 100% | 9.7% | | 0.0 |

282. The Company maintains that its proposal for rate design will move residential customers much closer to cost-based rates. After an initial residential rate increase of 14% in 2009, Minnesota Power is proposing two additional phased-in increases of 5% in 2010 and 2011. This phase-in is balanced by a comparably larger initial increase in the Large Power class, with corresponding reductions of that Large Power rate increase in tandem with the Residential class phase-in.[386]

283. The MCC would prefer a rate design that reflected customers' full cost of service, but it supports Minnesota Power's proposal for rate design as a step in that direction.[387]

284. The OES agrees with MP that the existing residential class subsidy needs to be reduced. The OES supported the revenue apportionment among classes that the Company initially proposed, as well as the costs of serving each class identified in MP's CCOSS.[388] However, the OES later added a qualification to that support. Minnesota Power identified three Large Power customers who have recently signed contract amendments that impact MP's sales and revenue forecasts, and the Company is seeking adjustments to its revenue deficiency based on those amendments. The Company is also seeking adjustments resulting from changes to contracts with two Large Light & Power customers.[389] The OES objects to those adjustments and takes the position that

[385] Ex. 115, Peirce Direct, at 6.
[386] Ex. 10, McMillan Direct, at 29.
[387] MCC Brief, at 1-3.
[388] Ex. 115, Peirce Direct, at 6.
[389] Ex. 116, Peirce Surrebuttal, at 5.

if the Commission were to grant the adjustments, they should be recovered from the affected customer class.[390]

285. The OAG/RUD denies the existence of any current subsidy of residential class customers. It argues that no fully distributed, embedded CCOSS can be used to support the finding of a subsidy because it assigns joint and common costs to customer classes,[391] and it asserts that the Company's CCOSS has been skewed to overemphasize costs to the Residential class. As an example, the OAG/RUD notes that 11% of the kWh sales were allocated to the Residential class, while the CCOSS assigns 12.7% of the rate base cost of generation and transmission to that class. By contrast, the OAG/RUD points out that the Large Power class purchases 69% of the power, but is only assigned 65% of the generation and transmission cost.[392] The OAG/RUD further argues the Peak and Average method that the Company used to allocate production and transmission costs was a subjective choice and inferior to other possible methods of allocation.[393] Assuming that, as Company argues, its unique concentration of large customers poses a risk to investors and increases the cost of capital, the OAG/RUD also argues that that factor should be taken into consideration in the allocation of costs, with the large power class responsible for costs in proportion to the risk it poses to the Company.[394]

286. The ECC maintains that both Minnesota Power and the OES have ignored Commission precedents establishing that non-cost factors should be taken into account when setting class revenue requirements that govern rate design. More specifically, the ECC argues that both the Company and the OES have given insufficient consideration to ability to pay. The ECC argues that nearly forty percent of MP's residential customers will experience 42-55% rate increases, and that since the Company's proposal adversely affects a significant number of MP's customers, particularly low usage and low and fixed income customers, the proposal is both inequitable and unreasonable.[395]

287. The LPI's position is that the inter-class subsidy that residential customers are currently receiving from Large Power customers is inherently inequitable and should be eliminated.[396] The goal should be to fully reflect the results of the Company's cost of service study, which requires eliminating all inter-class subsidies.[397] To the extent the Commission approves an increase that is smaller than the Company has requested, the LPI argue that the reduction should be first used to reduce or eliminate the subsidy paid by the Large Power class.[398] If the Commission approves a fairly small reduction of the Company's

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[390] *Id*.
[391] OAG/RUD Reply Brief, at 2.
[392] OAG Brief, at 19-20.
[393] *Id*. at 28.
[394] *Id*. at 23.
[395] ECC Brief, at 16-18.
[396] Ex. 67, Selecky Direct, at 7, 21.
[397] *Id.* at 19.
[398] *Id*. at 21-22.

requested increase, the LPI recommends that the phase-in of residential rates be expanded to include further 5% residential increases in 2012 and 2013 and that there should be corresponding reductions of the subsidies paid by rate classes whose rates are above cost of service.[399]

288. In analyzing MP's CCOSS, the OES considered the extent to which revenue apportionment assigned to each customer class a percentage share of the Company's revenue requirement in a way that satisfies four rate design principles: (1) provide the utility a reasonable opportunity to recover its revenue requirement (thus, 100 percent of cost responsibility is assigned to customer classes as a total); (2) ensure, as much as possible, that each class recovers all of the costs identified by the CCOSS as caused by that class, without subsidization or subsidy, in order to enhance efficiency and encourage conservation; (3) avoid sudden dramatic rate changes that may cause "rate shock;" and (4) establish rates that are understandable.[400] The OES's proposed revenue allocation reasonably meets criteria 2 and 3, above, by reducing inter-class subsidies while avoiding rate shock. The OES's proposal results in moderate percentage increases in the allocation of cost responsibility to the Residential and General Services class customers, which under MP's current rate design are assigned substantially less revenue responsibility than their respective costs of service.[401]

289. The Commission has historically considered a variety of cost and non-cost factors when designing rates. As the Minnesota Supreme Court explained in *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*:

> Once revenue requirements have been determined, it remains to decide how, and from whom, the additional revenue is to be obtained. It is at this point that many countervailing considerations come into play. The commission may then balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among the consumer classes.[402]

290. The Commission has also identified a number of cost and non-cost factors to consider when determining customer class revenue responsibility. Both types of factors are important to determine just and reasonable rates. The factors identified by the Commission include avoidance of rate shock for individual customer classes, low-income customers' ability to pay, a company's ability to recover the rate increase from others, the ability of

[399] *Id*. at 22.
[400] Ex. 115, Peirce Direct, at 2-3.
[401] Ex. 117, Peirce Recalculation, at Table 1.
[402] *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 312 Minn. 250, 260, 251 N.W. 2d 350, 357 (1977).

companies to decrease the burden of a rate increase through tax deductions, and the recognition of the historical continuity of rates and rate increases.[403]

291. The intervenors have offered differing proposals for customer class revenue responsibility. The LPI's proposals reduce inter-class subsidies, but could result in increases for some classes that are large enough to result in rate shock.[404] The OAG/RUD and the ECC argue, in effect, that subsidies to the residential and general service classes should be increased.[405] The OES supports the Company's customer class revenue allocation, subject to the Commission denying certain adjustments which the Company is seeking.

292. Of the various revenue allocation proposals, the ALJ concludes that a modification of the MP/OES allocation proposal best reflects and balances the relevant cost and non-cost factors. The ALJ has recommended elsewhere that the Commission grant the downward revenue adjustment that MP is seeking for LLP customer Ainsworth, but that the Commission adjust the revenue forecast that MP is proposing for Polymet upward, as recommended by the OES.[406] The ALJ has further recommended that the Commission deny MP's request to make downward adjustments to the sales forecasts of Large Power customers Hibbing Taconite, United Taconite, and Enbridge based on proposed contractual rate changes.[407] If the Commission accepts those recommendations, then the ALJ further recommends that the adjustments made to the revenue forecast of the Large Power class be allocated to that customer class for recovering required revenue, as proposed by the OES. With those exceptions, the ALJ concludes that the revenue apportionment proposed by MP minimizes the effects of rate shock, while modestly addressing subsidies between customer classes and therefore recommends that revenue apportionment.

### B. MP's Composite Allocation Methodology.

293. Minnesota Power used an allocation method called the Peak and Average ("P&A") method to allocate production and transmission fixed costs in its CCOSS.[408] Under that method, the demand related classification of fixed costs is calculated by dividing a class annual coincident peak ("CP") or demand by the sum of the system annual CP or demand plus the average demand or energy. The coincident peak is the demand that a rate class experiences at the time of a system peak or maximum demand.[409]

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[403] *Id*.
[404] *See* Finding 287.
[405] *See* Finding 288.
[406] *See* Finding 55, *supra*.
[407] *See* Finding 60, *supra*.
[408] Ex. 45, Shimmin Direct, at 7.
[409] Ex. 67, Selecky Direct, at 10.

294. The LPI argued that the P&A method is flawed,[410] and that the coincident peak method, which uses the peak for each class at system peak demand to allocate the fixed costs of production and transmission, best reflects cost-causation.[411] However, the LPI indicated that if the Commission were to determine that average demand (usage) should be reflected in the allocation of fixed production and transmission costs, then the average and excess demand (A&E) method of fixed production and transmission costs would be a more reasonable method than the P&A method for giving weight to average demand or usage.[412] Nonetheless, the LPI recommended the Commission base the revenue allocation in this case on the cost of service study presented by the Company, but that for MP's next rate case, it would be more appropriate for the Company to base the allocation of revenues on the more traditional and cost reflective A&E method.[413]

295. Although the OES agrees that the Peak and Average method proposed by MP and the A&E method proposed by the LPI are among those recommended by NARUC,[414] the OES indicated that a third method—the Equivalent Peaker method, which the Commission has approved in its two most recent rate cases— was the most appropriate method for classifying and allocating production plant costs. Rather than change the allocation method in this rate case, the OES recommended that Minnesota Power use the Equivalent Peaker method in its next rate case, or explain why it had chosen to use a different method.[415]

296. Since none of the intervenors has objected to Minnesota Power's use of the P&A method to allocate production and transmission fixed costs in this rate case, the ALJ recommends that the Commission approve the Company's use of that method and direct MP to use a different method in its next rate case, if the Commission considers that to be appropriate.

**C. Residential and Dual Fuel Interruptible Residential Customer Charges.**

297. Customer billings are typically comprised of a monthly customer charge, paid by any customer connected to a utility's system, and usage charges for the electricity consumed. The monthly customer charges are set by class and may differ by zones within a utility's service area. MP's existing Residential Service Charge is $5.00 and includes the first 50 kWh of electricity usage. MP's CCOSS indicates that residential customer-specific costs are $24.79 per customer per month. Based on that analysis, the Company proposes to increase the Residential Service Charge to capture more, but not all, of that

[410] *Id*. at 11-13.
[411] *Id*. at 13.
[412] *Id*.
[413] *Id*. at 17.
[414] *See* "Energy Weighting Methods" section of the Electric Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners, at 49-58.
[415] Ex. 114, Ouanes Surrebuttal, at 11.

cost through the fixed monthly charge. MP indicated that because it recognizes "the imprecise nature of cost of service studies and the need to avoid extreme rate shock, Minnesota Power proposes to increase the Residential Service Charge to only $10.00 per month rather than all the way to $24.79."[416] The Company did not propose to increase in the Residential Service Charge for customers in the Residential Low Income Assistance Program (discussed in subsequent Findings).

298. To support its proposed increase in Residential Service Charge, Minnesota Power compared its proposal to the monthly service charges of several distribution cooperatives adjacent to Minnesota Power's service territory, which also provide electric service to residential customers. The Company argues that those rates would be "a good proxy for the level of service charge Minnesota Power ratepayers could reasonably tolerate because the customers/members of cooperatives live in the same region as Minnesota Power customers and are subject to similar economic conditions and financial challenges."[417] However, distribution cooperatives are member-owned, and their rate design is not necessarily comparable to that of investor-owned utilities, particularly one with the customer mix of Minnesota Power.[418]

299. As the OES observes, customer service charges set below cost represent an intra-class subsidy. Intra-class subsidies arise when some customers within a class pay more than the cost to serve them and subsidize other customers within the same class who pay less than the cost to serve them.[419] Intra-class subsidies occur when customer charges are set below costs. These intra-class subsidies occur because revenue responsibility apportioned to the class must be recovered either through the customer charge or through the energy charge. To the extent customer charges do not recover the full cost of connecting and keeping a customer on the system (including connecting to the system along with ongoing metering, billing, customer service and repair), the costs associated with these services will be recovered through the energy charge. As a result, customers with higher monthly usage pay through their energy charges not only for energy costs, but also for the customer costs added to the energy charge. High-usage customers are therefore responsible for the revenue that would otherwise have been collected in a monthly customer charge from low-usage customers.[420]

300. Because the Company's current $5.00 per month Residential Service Charge does represent an intra-class subsidy, the OES agrees with the principle of moving customer services charges closer to cost over time, but it believes that MP's proposal both to double the customer charge and to eliminate the first 50 kWh from the customer charge could result in rate shock for residential customers. The OES therefore recommends

[416] Ex. 50, Podratz Direct, at 42.
[417] Ex. 50, Podratz Direct, at 43.
[418] OAG/RUD Brief, at 40.
[419] Ex. 115, Peirce Direct, at 10-11.
[420] *Id*. at 11.

moderating the increase in the proposed customer charge from the proposed $10 to $8 per month as a means of reducing rate shock.[421]

301. On the other hand, both the OAG/RUD and the ECC object to the Company's proposed increase in the Residential Service charge for residential classes and propose that MP retain the existing customer charge of $5.00 for all residential classes.[422] They maintain that a 100% increase of the Residential Service charge constitutes rate shock, is based on an imprecise and defective CCOSS, and is inconsistent with residential service charges that the Commission has recently approved for other publicly owned utilities.[423] The OAG/RUD and the ECC also assert that any increase in the customer charge contravenes the directive in Minn. Stat. § § 216B.03 to promote conservation.[424]

302. Additionally, both the OAG/RUD and the ECC argue that even the lesser charge recommended by the OES still amounts to a 60% increase in the customer charge and is unreasonable.[425] Noting that an increase of that magnitude was rejected by the Commission in the *2005 CenterPoint Energy Rate Order*,[426] the OAG/RUD and the ECC maintain that the Commission's reasons for rejecting the increase in that matter apply with equal force in this proceeding.[427] The ECC also points out that the Commission's decision in that case was based, in part, on the desire to promote conservation.[428]

303. The Commission has described its approach to customer service charges as follows:

> The customer charge has two main functions, one practical and one grounded in ratemaking policy. Its practical function is to help stabilize utility revenues and reduce the risk that the utility will over- or under-recover its revenue requirement due to weather-related fluctuations in gas usage and sales. Its ratemaking function is to ensure that each customer bears responsibility for a certain level of the Company's fixed costs regardless of usage.[429]

After acknowledging that Residential customer charges cause customer dissatisfaction, the Commission went on to state:

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421 Ex. 115, Peirce Direct, at 9-10.
422 OAG/RUD Brief, at 39-42; ECC Brief, at 18-19.
423 *Id*.
424 OAG/RUD Brief, at 41-42; ECC Brief, at 18.
425 OAG/RUD Brief, at 38-39; ECC Reply, at 18-19.
426 *ITMO an Application by CenterPoint Energy Minnegasco, for Authority to Increase Natural Gas rate,* Docket No. G008/GR-04-901 (Commission's Order Accepting and Modifying Settlement and Requiring Compliance Filing June 8, 2005) ("*2005 CenterPoint Energy Rate Order*")).
427 OAG/RUD Brief, at 38-39; ECC Reply, at 18-19.
428 *Id.* at 12-13 (quoting from *2005 CenterPoint Energy Rate Order*).
429 *2004 Xcel Energy Natural Gas Rate Case,* at 6 (Commission Order Accepting and Modifying Settlement and Requiring Compliance Filings issued August 11, 2005).

> [C]ustomer charges play an important role in the rate structure. They reduce utilities' capital costs by ensuring baseline levels of revenue, thereby reducing consumers' rates. They help mitigate rate volatility between seasons by recovering some fixed costs during the low-usage, summer months. They promote equity by ensuring that the rate structure does not shift the full system-costs imposed by low-usage and seasonal customers to normal-usage, high-usage, and year-round customers.[430]

304. In this rate proceeding, the ALJ concludes that the OES has demonstrated that an increase in the Residential customer charge to $8.00 appropriately assigns costs to that class, while avoiding customer confusion or rate shock. The ALJ therefore recommends that the Commission reduce the Company's proposed Residential Service Charge from $10.00 to $8.00 per month.

305. The Company also proposes to increase the Residential Service Charge for Dual Fuel Interruptible residential customers from $5.00 to $10.00 to correspond with its proposal to increase the service charge for residential customers.[431] Although none of the Intervenors specifically addressed that issue, the ALJ also recommends that the Commission reduce that service charge from $10.00 to $8.00 per month to bring it into conformity with the ALJ's recommendation on the residential customer charge.

**D. Seasonal Residential Customer Charge.**

306. Minnesota Power proposed that the Seasonal Residential Service Charge be set 10 percent higher than Residential Service Charge. It therefore proposed a Seasonal Residential Service Charge of $11 per month, or 10 percent higher than its proposal for the Residential Service Charge. The Company also proposes to begin billing Seasonal customers on a monthly rather than an annual basis.[432] Following the Company's suggestion that the Seasonal Residential customer charge should be 10 percent higher than the Residential Service Charge and with the OES's proposed Residential customer charge of $8.00, the OES recommends a Seasonal Residential Service Charge of $8.80 per month. It also recommends approval of MP's proposal to implement monthly billing for its Seasonal customers.[433] Again, none of the other intervenors addressed the Seasonal Residential Customer Charge.

307. The ALJ concludes that a Seasonal Residential Service Charge of $8.80 and billing seasonal customers on a monthly, rather than annual, basis are both reasonable and recommends that the Commission approve those proposals.

[430] *Id.* at 7.
[431] Ex. 50, Podratz Direct, at 45-46.
[432] Ex. 15, Peirce Direct, at 20.
[433] *Id.*

## E. General Service Energy and Customer Charges.

308. Minnesota Power proposes an increase in the energy charge for General Service customers with demand meters to 6.75¢ per kWh, with a demand charge to $6 per kW per month. The Company proposes an increase of the energy rate for General Service customers without demand meters to 8.5¢ per kWh. Finally, the Company proposes an increase in the monthly service charge for General Service customers from $3.81 to $8.50 per month.[434]

309. The OES expressed no opposition to the Company's proposed demand and energy rates for the General Service class but maintains that the proposed $8.50 per month service charge is set too low in comparison to that class' relative cost of service. The OES argues that a service charge of $10.50 will recover the same ratio of class-specific costs, as measured under the CCOSS, as the OES proposed $8.00 service charge will recover for the Residential class.[435] Minnesota Power did not oppose the OES proposal and noted that increasing the Service Charge for the General Service class would result in a corresponding reduction in the General Service class energy rates, and that the total revenue requirement for the General Service class would therefore not change.[436]

310. The OAG/RUD objects to both the Company and the OES proposals for higher service charges for the general service class. It points out that the Company's current General Service Charge is $3.81, and that an increase to $8.50 per month is excessive and unreasonable burden on small businesses in these difficult economic times.[437] None of the intervenors had specific positions or recommendations on the increases in energy rates for General Service class customers.

311. The ALJ concludes that a service charge of $10.50 for General Service Customers is commensurate with the recommended increase for Residential customers and is not unreasonable, particularly since it will be offset by a corresponding reduction in energy rates for that class. The ALJ therefore recommends that the Commission approve that service charge. The ALJ also recommends that the Commission approve the Company's proposed increase to 6.75¢ per kWh in the energy charge for General Service customers with demand meters, and that the demand charge for those customers be increased to $6 per kW per month. Finally, the ALJ recommends that the energy rate for General Service customers without demand meters be increased to 8.5¢ per kWh.

[434] Ex. 50, Podratz Direct, at 46-47; Ex. 115, Peirce Direct, at 20.
[435] Ex. 115, Peirce Direct, at 20-22.
[436] MP Brief, at 95.
[437] OAG/RUD Brief, at 42-43.

## F. Residential Rate Restructuring (Lifeline vs. Low Income Rider).

312. Currently the Company does not have an energy assistance program targeted to low income customers. Rather, all of its residential customers benefit from an increasing block rate structure known as the Lifeline Rate. Under the existing Lifeline Rate, residential customers are not charged for their first 50 kWh of usage; the cost of that energy usage is included in their monthly customer charge. Residential customers then pay for the next 300 kWh of monthly usage at a discounted rate of 4.773¢ per kWh, plus an additional 1.058¢ per kWh for the fuel adjustment for the test year.[438] The energy rate for monthly usage over 350 kWh is 7.218¢ per kWh, plus an additional 1.058¢ per kWh for the fuel adjustment for the test year.[439]

313. Minnesota Power proposes to eliminate the Lifeline Rate block structure and replace it with a flat Energy Charge of 8.3¢ per kWh for all energy usage, based on MP's initial calculation of revenue deficiency.[440] The Company contends that its proposed residential rate structure "works better to collect the portion of customer-related costs not collected through the monthly Service Charge, as compared to a discounted rate for the first energy block."[441]

314. On the other hand, the Company is proposing a new Residential Low Income Assistance Program ("Low Income Rider") to meet the needs of the Company's low income residential customers. One feature of that program is retaining the existing Residential Service Charge of $5.00 for customers enrolled in the program, although that reduced customer service charge would no longer include any energy usage component. Low Income Assistance Program participants would then pay a discounted energy charge of 7.25¢ per kWh (based on MP's claimed revenue deficiency). MP argues that this charge "is very close to the rate that currently applies to standard firm Residential customers for energy usage above 350 kWh per month." 442

315. Customers eligible for the Residential Low Income Assistance Program and its discounted service charge and rate will be customers who qualify for the federal Low Income Heating and Energy Assistance Program (LIHEAP). To identify qualified customers, the Company will rely on information obtained from those outside agencies that now qualify low-income residents for heating assistance programs. MP indicates that this approach will minimize the administrative burden and presumably program implementation costs.[443]

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[438] Tr. Vol. 1, at 104 (McMillan); Ex. 52, Podratz Rebuttal, Sched. 15, at 1 of 2.
[439] MP Brief, 89-90; Ex. 52, Podratz Rebuttal, Sched. 15, at 1 of 2.
[440] Ex. 52, Podratz Rebuttal, Sched. 15, at 2 of 2.
[441] Ex. 50, Podratz Direct, at 44.
[442] Ex. 50, Podratz Direct, at 44.
[443] Ex. 50, Podratz Direct, at 44.

316. The ECC cites statistics that approximately 111,266 households within MP's service territory live at or below 50% of the State Median Income and are income-eligible for LIHEAP. The ECC contends that the majority of eligible low-income households in MP's service territory do not receive LIHEAP because they do not apply for the program. Believing that the majority of MP customers who are income-eligible do not apply for LIHEAP, the ECC argues that LIHEAP qualification is "not a good proxy for identifying low-income customers or for ascribing attributes to them."[444] In support of its position the ECC relies on the results of MP's last rate proceeding and a more recent gas rate matter for the proposition that LIHEAP does not constitute an acceptable substitute for identifying low-usage customers.[445]

317. The ECC notes that of the 111,266 households in MP's service territory that are income-eligible for LIHEAP, only between 9,716 and 12,695 received a LIHEAP grant. Of those who received grants, ECC argues that only approximately 6,000 households applied any portion of the grant money to their MP electricity bill.[446]

318. The ECC also asserts that one-quarter of MP's residential customer base (24.8%, or 27,197 customers) use less than 350 kWh (Lifeline level). Therefore, the ECC argues that MP is proposing the largest percentage rate increases in the lowest usage tiers. It further maintains that the combined elimination of the Lifeline Rate, the increase in the customer service charge (to those not in the Low Income Rider), and the volumetric charge increase in the lowest usage tier, will adversely affect that group of customers the most. The ECC asserts that while low usage customers are more likely to be low and fixed income customers, only 2,100 of the Lifeline level customers receive LIHEAP.[447] ECC maintains that the combination of these factors results in rates that are not just and reasonable. Further, ECC argues that the proposed rate design regarding low income customers violates Minn. Stat. § 216B.16, subd. 15, which requires the Commission to consider a customers' ability to pay in setting rates.[448]

319. The OES argues for limited retention of an increasing block rate structure, to the extent incorporated in the Low Income Rider. The OES agrees with limiting participants to those Residential customers who qualify for heating assistance under LIHEAP. The OES notes that, as proposed, the Low Income Rider program will result in an intra-class subsidy, since non-qualifying Residential customers will pay more for electric service to make up the difference in class cost responsibility.[449] The OES maintains that this subsidy would be most pronounced with high usage Residential customers subsidizing low usage Residential customers. However, the OES observes that the amount of intra-

[444] Ex. 85, Marshall Direct, at 10-12, Attachment A; ECC Brief, at 6.
[445] ECC Brief, at 7-9 (citing *2005 CenterPoint Energy Rate Order*, at 7).
[446] Ex. 85, Marshall Direct, at 10-12; ECC Brief, at 6.
[447] Ex. 81, Podratz chart.
[448] ECC Brief, at 15.
[449] Ex. 115, Peirce Direct, at 16-17.

class subsidy will be limited through constraints on the number of LIHEAP income-eligible customers. The OES concludes that MP's proposal, "by lowering both the customer charge and the energy charge for qualifying low income customers, is intended to provide some assistance as to lower bills for low usage, low income customers (to the extent the customer charge is lowered), and will give some help for high usage, low income customers (to the extent the energy charge is discounted)."[450] The MCC also supports the Company's proposed Low Income Rider.[451]

320. In the ALJ's view, Minnesota Power's current Lifeline Rate is significantly over-inclusive in that it provides an intra-class subsidy based on usage that benefits residential customers of all income levels rather than being targeted to low income customers. While the Company's proposed Low Income Rider still involves an intra-class subsidy by discounting the customer and energy charges paid by low income customers, the benefits are more narrowly targeted to low-income customers. The ALJ concludes that some degree of intra-class subsidy targeting low income customers is warranted, given indicators that a greater number of residents in the Company's service area have low incomes than those in other parts of the state.[452] MP's proposed Low Income Rider addresses both low- and high-usage low income customers, by providing some assistance with both the customer and energy charges. The ALJ therefore recommends that the Commission approve the Company's discontinuance of its Lifeline Rate and replacement of that rate with the Company's Low Income Rider.

**G. Dual Fuel Interruptible Residential Service Tariff.**

321. The Dual Fuel Interruptible Residential Service rate is available to residential customers with electric heating. To qualify for the rate, a customer must have a non-electric backup heating system, which must provide up to 30 percent of the customer's heating during the year. When demand for power is high, Minnesota Power can interrupt electric heating, whereupon the backup heating system takes its place. Converting to dual fuel interruptible service involves significant investment by the homeowner.[453] During the public hearings, dual fuel customers emphasized the need for them to have an energy rate lower than the rate for other residential customers to enable dual fuel customers to recover their investment within a reasonable time.[454]

322. The Company is proposing an increase in the energy rate from 3.7¢ to 6¢ per kWh, an increase of 2.3¢ per kWh.[455] Minnesota Power based its proposed increase in the Residential Dual Fuel rate on an analysis of the Company's incremental cost of providing Dual Fuel service, as well as comparisons with current prices of other home

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450 OES Brief, at 111-112; Ex. 115, Peirce Direct, at 16-17.
451 MCC Brief, at 4-5.
452 Ex. 85, Marshall Direct, at 10-13.
453 OAG/RUD Brief, at 47.
454 *See* Finding 16, *supra*.
455 *Id*.; Ex. 50, Podratz Direct, at 45-46.

heating fuels such as propane, fuel oil, and natural gas. Nevertheless, the OAG/RUD objects to the increase as being too high, noting that the difference between the Residential and Dual Fuel service rates is currently 3.5¢, while under the Company's proposal the difference will be 2¢.[456] The OAG/RUD believes this reduction in the difference of the Residential and Dual Fuel service rates may actually discourage customers from using dual fuel service.[457] No other intervenor raised objections to the proposed duel fuel energy rate.

323. Since the rate that Minnesota Power is proposing for dual fuel residential customers has an empirical basis and since the OAG/RUD has not presented evidence to support its concerns, the ALJ recommends that the Commission approve the Company's Dual Fuel Interruptible Residential Service tariff.

## H. Triple E and Residential Heat Pump Service Tariffs.

324. Minnesot a Power is proposing a new Triple E and Residential Heat Pump Service with discounted tariffs for Residential class customers having either a Triple E certified home or a Ground Source or Air Source Heat Pump for heating or cooling. That new tariff would involve a discounted energy charge for Triple E customers of $0.073 per kWh, and for heat pump customers of $0.063 per kWh. The Company argues that these discounts will provide incentives for additional Residential customers to invest in technology that results in lower energy use.[458]

325. The OES urged denial of the Company's proposed Triple E and Residential Heat Pump Service tariff changes for several reasons. First, although the new tariffs are designed to promote energy efficiency and conservation technologies, the OES believes that the discounted energy charge sends the wrong price signal for conservation by telling customers to use more electricity. Second, since heating and cooling usage increase during the peak times of the day, discounting the energy charge under both tariffs provides no incentive to reduce on-peak usage. Third, the Company itself indicates that it expects a number of its customers with either Triple E certified homes or heat pumps to move from Residential Dual Fuel Service, an interruptible service, to the new tariffs, which provide firm service. While Dual Fuel Service customers receive a discounted energy charge, they must have an alternative fuel source available and allow the Company to interrupt their energy when needed. In contrast, customers on either the Triple E or Residential Heat Pump service tariffs will receive a discounted energy charge without any interruption to their service or reduction in the underlying cost to serve them. Finally, the OES contends that the proposed energy discounts in the Triple E and Residential Heat Pump Service rates would result in an unwarranted intra-class

[456] OAG/RUD Brief, at 48.
[457] *Id.*
[458] Ex. 50, Podratz Direct, at 46; Ex. 115, Peirce Direct, at 22-23.

subsidy for those customers, a subsidy that would be available to existing customers, as well as new customers.[459]

326. In response, Minnesota Power argues that while the dual fuel interruptible service option encourages customers to reduce on-peak consumption by offering a discount rate in exchange for taking interruptible service, the Triple E and Heat Pump service options encourage customers to reduce overall energy consumption by offering a discount rate for employing these energy efficient technologies. MP asserts that the efficiency of these technologies "can dramatically reduce the energy demand placed on Minnesota Power's system, and the discount rate is a critical element in reducing the payback period for the customer's investment in the new technology."[460]

327. Although the Company's proposed new Triple E and Residential Heat Pump Service tariffs would have the salutary effect of encouraging residential customers to invest in new, energy efficient technologies, the ALJ concludes that the potential adverse consequences of establishing those new tariffs outweigh that potential benefit. The ALJ therefore recommends that the Commission not approve those new tariffs.

## I. Large Light and Power.

328. Minnesota Power's existing Large Light and Power tariff (LLP) is available to customers with total power requirements of less than 10,000 kW. Minnesota Power proposed to increase the limit for the tariff to all customers with total power requirements of less than 50,000 kW. MP explained that some large customers have load profiles that do not fit well with the Company's Large Power class requirements. This change is proposed to give those customers another service option. The LLP demand charge would be $8.00 per kWmonth, with an energy rate of 4.5¢ per kWh.[461] The OES supports this proposal, and none of the other intervenors opposed it.[462] The ALJ therefore recommends that the Commission approve the Company's proposed demand charge of $8.00 per kWmonth and energy rate of 4.5¢ per kWh for LLP customers.

## J. Large Power.

329. The primary change in the Large Power class is Minnesota Power's proposal for a 3.5% increase in rates with higher rates that are phased downward to coordinate with phased-in increases for the Residential class. Those changes are discussed in foregoing Findings. Along with the rate increase, Minnesota Power proposed a number of changes to the Large Power Service Schedule and associated Riders as follows:

[459] Ex. 115, Peirce Direct, at 25-26; Ex. 116, Peirce Surrebuttal, at 2-3.
[460] Ex. 52, Podratz Rebuttal, at 30-31.
[461] Ex. 50, Podratz Direct, at 47.
[462] Ex. 115, Peirce Direct, at 28.

a) Increase the Demand Charge for the first 10 kW or less of Billing Demand to $161,385.

b) Combine the Demand Charges for Firm Power and Excess Power into one Firm Power Demand Charge of $15.10/kw-month.

c) Add time-of-use energy rates, proposed to be 2.8¢/kWh on–peak and 1.2¢/kWh off-peak for Firm Energy.

d) Clarify the applicability of the Large Power Surcharge, including increasing the threshold for its application to 50,000 kW.

e) Add a non-curtailable option to the Rider for Large Power Incremental Production Service.

f) Expand the application of the Rider for Expedited Billing beyond the taconite customers to all Large Power customers.

g) Eliminate the Rider for Implementing "Best Efforts" Marketing Policy- Large Power Class.

h) Increase the Service Voltage Adjustment to $1.50/kWh-month.[463]

330. LPI and Boise objected to the application of the Expedited Billing Rider being expanded to cover non-taconite industrial customers of Minnesota Power (item f above).[464] Boise also objected to the elimination of the Excess Demand Rate from the Large Power tariff (item b. above).[465] The OES objected to MP's proposed time-of-use rates (item c above).[466] Minnesota Power settled those issues in the course of the parties' settlement of the fuel clause lag recovery issue, discussed in Findings 228 to 231.[467] None of the parties objected to the other items proposed above.[468] The ALJ therefore concludes that the changes set forth above, unless withdrawn by the Company as part of the stipulated settlement, are reasonable and should be approved by the Commission.

[463] Ex. 50, Podratz Direct, at 48.
[464] Ex. 67, Selecky Direct, at 23-26; Ex. 69, Selecky Surrebuttal, at 6; Ex. 109, Ward Direct, at 11.
[465] Ex. 109, Ward Direct, at 7-10.
[466] Ex. 109, Ward Direct, at 7-10; Ex. 115, Peirce Direct, at 30-32; Ex. 116, Peirce Surrebuttal, at 4-5.
[467] Ex. 107, Stipulation and Settlement Agreement; MP Brief, at 97.
[468] MP Brief, at 96-97.

## XVI. RESOLVED ISSUES

### A. Results Sharing Compensation.

331. MP indicated that an issue regarding Results Sharing Compensation was agreed to with no adjustment needed.[469]

### B. Hibbard Energy Center.

332. With regard to the Hibbard Energy Center there was no dispute over an adjustment of $(27,183) to include depreciation expense and associated taxes.[470]

### C. Brainerd Public Utilities Commission Asset Sale.

333. With regard to the Brainerd Public Utilities Commission Asset Sale there was no dispute over an adjustment of $(4,289) to include depreciation expense and associated taxes.[471]

### D. Conservation Improvement Plan Expenses.

334. There was no dispute over an adjustment of $219,810 to reflect the average of 2008 and 2009 Conservation Improvement Plan expenses for the test year, and associated taxes.[472]

### E. Property Taxes.

335. With regard to Property Taxes there was no dispute over an adjustment of $(384,338) to reflect actual test year property tax expenses.[473]

### F. Service Life Petition for Transmission and Distribution.

336. There was no dispute over an adjustment of $(306,653) to include test year plant-in-service balance and related depreciation.[474]

### G. Interest on LP Expedited Billing.

337. There was no dispute over an adjustment of $107,077 to include all costs in retail rate case

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[469] *Id*.
[470] *Id*.
[471] *Id*.
[472] *Id*.
[473] *Id*.
[474] *Id*.

(as opposed to allocating a portion to FERC jurisdiction) because interest on LP expedited billing relates only to retail rate class.[475]

## H. Fuel and Purchased Power Deferral (Miscellaneous and General Expenses).

338. There was no dispute over an adjustment of $(3,017,465) to fuel clause lag costs, to reflect Minnesota Power's request for consideration in fuel clause docket.[476]

## I. Badoura-Pine River Project.

339. There was no dispute over an adjustment of $ (19,204) to include depreciation expense and associated taxes relating to the Badoura-Pine River Project.[477]

## J. BEC4 – Boiler Surface Project.

340. There was no dispute over an adjustment of $(4,870) to include depreciation expense and associated taxes relating to the BEC4 – Boiler Surface Project.[478]

## K. Depreciation Expenses.

341. There was no dispute over an adjustment of $(324,532) to account for depreciation expenses under a recent Commission decision.[479]

# XVII. CONCLUSIONS.

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. Ch. 216B and section 14.50.

2. Any foregoing Finding which contains material which should be treated as a Conclusion is hereby adopted as a Conclusion.

3. MP has shown that the issues that have been resolved result in rates that are in the public interest and those issues should be approved by the Commission.

4. MP has not shown that its proposed capital structure accurately reflects an appropriate division of debt and equity. The OES proposal regarding an imputed capital

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[475] MP Brief, at 63-65.
[476] *Id*.
[477] *Id*.
[478] *Id*.
[479] *Id*. (citing *ITMO Minnesota Power's Five-Year Review of Average Service Lives for Transmission and Distribution Plant Accounts for 2008*, Docket No. E-015/D-08-422).

structure does reflect an appropriate division of debt and equity and should be adopted in calculating required revenue.

5. MP has not demonstrated that its proposed return on equity (ROE) strikes an appropriate balance between the interests of shareholders and ratepayers. The OES has demonstrated that its methodology to compute the ROE is better justified, and that methodology should be adopted in this matter. The ROE figure of 10.74 percent is appropriate and should be used to determine the allowable return on revenue (ROR) in this matter.

6. With adoption of the OES-proposed capital structure, MP's appropriate allowable ROR is 8.31 percent for rate setting purposes.

7. The proposed changes in tariff provisions, with two exceptions, are reasonable and should be approved. The proposed Triple E and Residential Heat Pump tariff changes have not been shown to be reasonable and should not be approved.

8. For asset-based margins, the fixed credit of $34,958,638 as proposed by OES is reasonable and should be adopted for rate-setting purposes.

9. For non-asset-based margins, the OES proposal of a $300,000 cap on ratepayer responsibllity for losses arising from virtual transactions to hedge against price shifts in the Day-Ahead and Real Time markets is reasonable and should be adopted.

10. For ancillary service market margins, the OES proposal that these issues be addressed in the *ASM Docket* is reasonable and should be adopted.

11. Regarding $SO_2$ and $NO_x$ allowances, a credit of $195,000 should be made to base rates for the EPA sales expected during the test year. For the remaining allowance sales, those amounts should be returned to ratepayers through a cost recovery rider.

12. MP has demonstrated that the test year expenses for MISO Schedule 16 and 17 costs of $1,326,277 are appropriate for recovery through base rates. MP has demonstrated that deferred Schedule 16 and 17 costs of $4,423,480 should be recovered on an amortized expense basis. The appropriate amortization period is five years, unless the Commission orders MP to file another rate case within three years, in which case the amortization should occur over three years. MP has not shown that any of the amortized expense amounts are approroprite for inclusion in its rate base.

13. MP's test year revenue forecast is appropriately increased by $4,070,155 for Other Wheeling Revenue. MP has shown that it had not accounted for test year expenses arising from the Ontario Path purchases of electricity and those expenses should be increased by $2,822,776 (Minnesota Jurisdiction).

14. MP has demonstrated that AREA Plan expenses up to the $4.07 million cap imposed by the Commission are reasonable and should be included in MP's test year O&M expenses. MP has not demonstrated that the Minnesota jurisdictional amount of $568,533 is sufficiently certain, reasonable, or reliable for inclusion in base rates.

15. MP has not demonstrated that its incentive compensation methodology and amounts are reasonable. The modifications proposed by the OES are consistent with prior Commission treatment of incentive compensation and result in rates that are just and reasonable. Imposing a tracking mechanism for actual amounts paid and a refund of unpaid incentive compensation already included in rates is reasonable and should be adopted.

16. MP has demonstrated that its test year corporate aircraft expenses of $1.2 million are appropriate for inclusion in rates.

17. MP has not affirmatively shown that its corporate cost allocation process conforms to the Commission requirements in the *Docket 1008 Order*. MP has not affirmatively shown that its test year corporate costs are appropriate for calculating base rates. The OES has demonstrated that its test year corporate cost calculation for MP of $73,678,620 is reasonable and should be adopted. The OES has not shown that requiring legal separation of Minnesota Power and ALLETE is needed or reasonable to address ongoing issues of corporate cost allocation.

18. MP has demonstrated that its use of the E8760 allocator is appropriate for calculation of cost responsibility between customer classes.

19. The stipulation between MP, OES, Boise, MCC, and LPI regarding the proposed FCA adjustment and other related billing issues is reasonable and should be approved by the Commission.

20. MP did not develop a quantitive methodology for analyzing the ratepayer impact of the Company's economic development programs. MP has demonstrated that its economic development expenses are beneficial to ratepayers sufficent to support the inclusion of 50 percent of those expenditures in MP's test year expenses for the calculation of base rates.

21. MP has demonstrated that it incurred reasonable rate case expenses in this matter of $1,191,789. The OES has shown that the overall expense should be reduced by 5.76 percent to reflect the portion of the expense that is allocable to nonregulated activities. The resulting amount should be recovered on an amortized expense basis. The appropriate amortization period is five years, unless the Commission orders MP to file another rate case within three years, in which case the amortization should occur over three years. MP has not shown that any of the amortized expense amounts are approroprite for inclusion in its rate base.

22. The agreed-upon adjustments to MP's rate base are reasonable and should be adopted. MP has not shown that the Asset Retirement Obligation

methodology (ARO Method) is superior to the Decommissioning method for calculating depreciation. MP's proposal to use the ARO Method in determing test year expenses should not be adopted.

23. The OES has shown that the Sappi 5 generation facility should be included in MP's rate base. MP has shown that the Rapids Energy Center should not be included in the Company's rate base. Should the Commission choose to put either or both facilities in the rate base, revenue and O&M expenses will need to be adjusted to reflect the facility put into the rate base. MP has shown that its revenue estimates are reasonable and should be adopted. The OES has shown that its O&M cost calcuation is reasonable. The Commission may also deny test year O&M expenses as not demonstrated or afford MP the opportunity to supplement the hearing record on this issue.

24. Use of the year ending on ending June 30, 2009, as a combined historical and projected test year for determining MP's revenue requirement is reasonable. The test year forecast of the total of MP's electricity sales, with the adjustments described in this Report, is reasonable. Calculation of the net required revenue adjustment is dependent upon the determination of the various issues before the Commission in this proceeding.

25. MP has demonstrated that it will experience a revenue shortfall. MP is entitled to recover this revenue shortfall through an adjustment of its electric rates to increase its revenues.

26. MP has demonstrated that its proposed allocation of the rate increase across customer classes meets the Commission's standards for rate design and does not result in rate shock. The OES proposal for adjusting the allocation to address changes in forecast revenues for customer classes, as modified in this Report, is reasonable and should be adopted. MP's replacement of the Lifeline Rate with its Low Income Rider meets the needs of low-income residential customers, while striking the best balance between the various rate design principles of the Commission.

27. MP has not demonstrated that an increase in the Residential Basic Charge from $5.00 per month to $10.00 per month is an appropriate adjustment to balance the need to recoup the costs of serving the residential class of customers without interclass subsidies, with the need to encourage conservation, avoid rate shock, and account for other factors between rate classes. Based on the record in this proceeding, OES has demonstrated that an increase in the residential basic charge to $8.00 per month is an appropriate adjustment that meets the Commission's standards for changes in rates.

28. MP has not demonstrated that an increase in the Seasonal Residential Service Charge to $11.00 per month is an appropriate adjustment. Using MP's methodology, an increase in the Seasonal Residential Service Charge to $8.80 per month is an appropriate adjustment that meets the Commission's standards for changes in rates.

29. MP has demonstrated that an increase in the General Service Customer Charge from the existing $3.81 per month is appropriate. The proposal from MP to increase the charge to $8.50 per month does not sufficently maintain the relationship between the charges on the Residential and General Service classes of customer. The ALJ concludes that the OES recommendation to increase the monthly charge to $10.50 is an appropriate adjustment to balance the need to recoup the costs of serving the General Service class of customers without interclass subsidies and with the need to encourage conservation, avoid rate shock, and account for other factors between rate classes. Based on the record in this proceeding, an increase in the General Service basic charge to $10.50 per month is an appropriate adjustment that meets the Commission's standards for changes in rates.

30. MP has demonstrated that its proposed replacement of the Lifeline Rate with a Low Income Rider meets the needs of low-income residential customers, while striking the best balance between the various rate design principles of the Commission.

31. Modifying MP's electric rates in the manner described in the Findings and Conclusions above results in just and reasonable rates that are in the public interest within the meaning of Minn. Stat. § 216B.11.

32. The rate finally ordered by the Commission should be compared to the interim rate set in the Commission's July 21, 2008 Order Setting Interim Rates, and a refund be ordered to the extent that the interim rate exceeds the final rate, subject to any true-up ordered regarding any particular expense.

Based on the foregoing Findings and Conclusions above, the Administrative Law Judge makes the following:

## XVIII. RECOMMENDATION.

IT IS RECOMMENDED that the Public Utilities Commission order that:

1. Minnesota Power is entitled to increase gross annual revenues in the manner and in an amount consistent with the terms of this Order.

2. Within 30 days of the service date of this Order, Minnesota Power shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement for annual periods beginning with the effective date of the new rates, and the rate design decisions contained herein. Minnesota Power shall include proposed customer notices explaining the final rates. Parties shall have 14 days to comment.

3. (If the Commission orders an Interim Rate Refund) within 30 days of the service date of this Order, Minnesota Power shall file with the Commission for its review and approval, and serve upon all parties in this proceeding, a proposed plan for refunding to all customers, with interest, the revenue collected during the Interim Rate period in excess of the amount authorized herein. Parties shall have 14 days to comment.

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| Dated: February 19, 2009 | /s/ Bruce H. Johnson |
| | BRUCE H. JOHNSON<br>Administrative Law Judge |

Reported: Shaddix and Associates
Transcripts Prepared (Six Volumes)