STATE OF NORTH DAKOTA

BEFORE THE

PUBLIC SERVICE COMMISSION

In the Matter of the Application by Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-07-776

XCEL ENERGY'S PROPOSED FINDINGS OF FACT, CONCLUSIONS AND ORDER

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TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

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The above-entitled matter came on for evidentiary hearing before Administrative Law Judge Al Wahl on June 23-25, 2008, in Bismarck, North Dakota.

The parties to this proceeding are: Northern States Power Company, a Minnesota corporation ("Company" or "Xcel Energy"); and the North Dakota Public Service Commission ("Commission") Advocacy Staff ("Advocacy Staff"). These parties, collectively, sponsored prefiled written testimony of 17 witnesses.

Appearances

Commissioners Susan E. Wefald, Tony Clark, and Kevin Cramer.

Megan J. Hertzler, Assistant General Counsel, Xcel Energy, 414 Nicollet Mall, Fifth Floor, Minneapolis, MN 55402, and Michael J. Bradley, Attorney at Law, Moss & Barnett, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, Minnesota 55402, for Xcel Energy.

Douglas A. Bahr, Solicitor General, Office of the Attorney General, 500 North Ninth Street, Bismarck, North Dakota 58501, for the Advocacy Staff.

PRELIMINARY STATEMENT

On December 7, 2007, Xcel Energy filed its application, including its Direct Testimony, with the Commission seeking a general revenue increase of $17,950,000 or 12.15 percent of total revenues (the "Application"), which was assigned Case No. PU-07-776 by the Commission. This base rate increase would be offset by a decrease in the fuel adjustment revenue requirement. For 2008, the offset would have been a $1,839,000 decrease in fuel adjustment rates, for a net revenue increase of $16,011,000.[1]

The Company stated that it needed this increase in revenues to maintain high quality service to customers and to support funding for future investments.

On January 16, 2008, the Commission issued a Notice of Public Input Session and Intervention Deadline.

On January 30, 2008, the Commission issued its Order on Interim Rates authorizing the Company to collect interim rates.

On March 23, 2008, the Commission issued its Notice of Hearing setting the dates for hearing and outlining the issues to be considered, including:

[1] This calculation is based on 2008 test year costs and revenues and reflects the Company's proposal to share 85% of asset-based wholesale margin credits ($1,800,000) and 15% of non-asset based margin credits ($39,000) through the fuel clause.

1. What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?

2. What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

3. What is a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

4. What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?

5. Are NSP's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?

6. Other relevant information or proposals concerning the proceeding.

The Notice of Public Input Session and Intervention Deadline provided that any person wishing to intervene as a party in this proceeding must file a petition for intervention by March 28, 2008. No one petitioned to intervene as a party in the proceeding.

A public input session was held via interactive television on March 14, 2008, simultaneously at various locations.

On May 21, 2008, the Advocacy Staff witnesses filed Direct Testimony.

On June 13, 2008, Rebuttal Testimony was filed by Xcel Energy.

The Commission hearings were held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota on June 23-25, 2008.

The Commission, having reviewed the evidence in the record, makes the following:

FINDINGS OF FACT

I. DESCRIPTION OF THE COMPANY.

1. Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") provides electric retail service in North Dakota and Minnesota. It serves approximately 86,000 customers in 27 communities and townships located in and near the cities of Fargo, Grand Forks, and Minot. 86 percent of its customers are residential and 14 percent are commercial and industrial. 36 percent of the Company's retail sales are to residential customers and 64 percent of its retail sales are to commercial and industrial customers.

II. ISSUES.

2. The parties do not dispute the following issues:

- The cost of capital, including ROE;
- The test year sales forecast;
- Recovery of MISO charges;
- The Company's proposed rate design; and
- The Company's proposed miscellaneous tariff changes.

3. The list of disputed issues includes, whether:

- investments made by the Company to rehabilitate the Allen S. King Plant and to reconfigure the High Bridge Plant were prudent and used and useful;
- expenditures made for environmental controls, and in particular mercury emission control were prudent and used and useful;

- North Dakota customers should pay a proportion of the costs of the Renewable Development Fund;
- the Company's depreciation study, including the remaining lives of its generation, deprecation methodology, and determination of retirement costs are reasonable;
- the Company should recover its costs associated with:
  wholesale margin sharing
  pole inspection and replacement and cable replacement programs
  private nuclear fuel storage costs
  charitable contributions
  incentive compensation; and
- there should be a change in:
  the resource planning process
  the process for determining depreciation rates.

III. BURDEN OF PROOF.

4. The Advocacy Staff asserts that, with regard to the Commission's review of the record in this proceeding, the Company did not satisfy its burden of proof with respect to any of Advocacy Staff's proposed adjustments.[2]

5. The Company agreed that it has the burden to prove the reasonableness of its request. However, it argues that, having responded to Advocacy Staff's proposed adjustments with substantial Rebuttal Testimony demonstrating that, with respect to each issue, its expenses, investments and actions have been in the best interest of all of its customers, it has met that burden.

6. The burden of proof is made up of two separate parts: "the burden of going forward with the evidence and the burden of persuasion."[3] During a rate

[2] Advocacy Staff Initial Brief at 4.

hearing: "the burden to show that the increased rate is just and reasonable is upon the public utility applying for the increase."[4] The burden of persuasion never shifts: "it remains with the party having the burden of proof."[5] This means that the burden of proving the reasonableness of its proposed rates stays with the Company throughout the proceedings.

7. However, the first component, the burden of going forward with evidence: "may rest … at one time upon the [utility] and at another time upon the [Advocacy Staff]."[6]

> If the party bearing the burden of proof presents evidence strong enough, if uncontradicted, to support a finding in her favor, that party has made a prima facie case. When the party with the burden of proof establishes a prima facie case, the burden of going forward with the evidence … shifts to the other party. If the other party can impair the prima facie quality of the case against him [*i.e.* rebut], the burden [of going forward] returns to the party having the burden of proof. If the party having the burden of proof establishes a prima facie case, this party will prevail unless the opposing party offers proof to the contrary.[7]

8. Once the Company provided sufficient evidence disproving a concern or claim by the Advocacy Staff's Consultants, it became the responsibility of the Consultants to provide affirmative evidence disputing the Company's evidence in order to defeat the Company's prima facie case.

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[3] *Helbling v. Helbling*, 541 N.W.2d 443, 445 (N.D. 1995).
[4] N.D. Cent. Code § 49-05-06.
[5] *Id.*
[6] *Id.*
[7] *Id.* (citations omitted).

9. In evaluating the evidence in this proceeding, the Commission has taken the respective burdens of both the Company and Advocacy Staff in making its decision.

IV. TEST YEAR RATE BASE.

10. The Commission finds the following 2008 test year rate base:

Rate Base	(Thousands) Balance
Plant in Service	$607,339
Accumulated Depreciation	$333,166
Net Plant	$247,173
Construction Work in Progress	$4,802
Cash Working Capital	$1,144
Less: Accumulated Deferred Taxes	$40,717
Materials and Supplies	$5,412
Fuel Inventory	$2,358
Non-Plant Assets & Liabilities	($6,928)
Prepayments	$1,127
Other Working Capital	$797
Customer Advances	($60)
Average Rate Base	$242,108

A. Whether The King And High Bridge Projects Were Prudent And Benefit All Customers.

11. Advocacy Staff proposed disallowing the entire cost of the King Plant rehabilitation and fifty percent of the cost of the High Bridge plant rehabilitation (combined these adjustments total approximately $4,465,000).[8] Both

[8] Ex. 21A, Heuer Rebuttal at 23-24.

recommendations were premised on a belief that: (i) the Company would not have undertaken either project without Minn. Stat. § 216B.1692; and (ii) both projects were premature. Section 216B.1692, Metro Environments Reduction Program ("MERP") allowed utilities to propose plant improvements that would reduce emissions and receive cost recovery in Minnesota outside of a rate case.

12. Advocacy Staff assumed that Minn. Stat. § 216B.1692 required the Company to develop a plan for projects that would qualify under that statute.[9] Minn. Stat. § 216B.1692, which was enacted in 2001, established a process for developing, approving and implementing appropriate projects,[10] but it did not require the Company to undertake any project.

13. Company viewed the statute as voluntary, providing an *improved mechanism* for implementing three projects that were already needed and that benefited all of the Company's customers:

> In fact, the MERP statute prohibits consideration of projects that are mandated or a result of corrective action due to being out of compliance with current standards. Xcel Energy proceeded with development of the three above-described projects [King, High Bridge and Riverside] on a voluntary basis because we believed they would provide significant benefits to its customers throughout its service territories.[11]

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[9] *See* Evidentiary Hearing, Vol. III at 640-641 (King).

Q. It is your impression that the company was obligated to establish a plan?

A. I believe it was, yes.

[10] Ex. 10, Engelking Rebuttal at 4.

[11] *Id.* at 5.

1. Whether The Rehabilitation Of The King Plant In 2005 Was Prudent And Benefits All Customers.

14. By 2001, the King Plant's forced outage rate had risen to levels that caused concern, and the plant was experiencing problems typical of a heavily used facility of its vintage.[12]

15. In 2001, the Company's Energy Supply division conducted condition assessments of both the King Plant's boiler and steam turbine. Components of the boiler were failing on a regular basis, reducing the availability, reliability and capacity factor. The frequency of the failures was rising.[13]

16. In 2001, Babcock and Wilcox ("B&W"), the Company's consulting engineers, conducted an assessment of the boiler and found that the boiler floor was in poor condition, physically distorted and metallurgically weak. B&W also reported that the floor and the cyclone burners of the King boilers were the longest surviving original components of 1960's vintage cyclone-fired boilers. The floors and cyclones of all similar boilers built by B&W had been replaced at least once.[14]

17. The King Plant would have ceased operations in 2005,[15] when the rehabilitation began. The Company, in 2003, proposed that the King Plant upgrades be the first MERP project to be implemented.[16]

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[12] *Id.*
[13] *Id.*
[14] *Id.*
[15] *Id.* at 7.
[16] *Id* at 9-10.

18. In addition, the Company demonstrated the following added advantages gained as a result of rehabilitating the King Plant:

- The rehabilitation reclaimed 60 MW of capacity at very little incremental cost.[17]
- The capacity factor of the plant increased from 74 percent to 82 percent and significantly improved the emission levels in the Company's Twin Cities Metropolitan service area.[18]
- The life of the plant was extended 25 years or more.
- Rehabilitating the plant was accomplished at approximately one-third the cost of constructing a new coal-fired facility, and the cost of additional transmission to serve a new plant would have further increased that cost differential. [19]

19. The Company's evidence demonstrates that the King Plant rehabilitation was prudent and benefits all of its customers.

2. Whether The High Bridge Conversion Was Prudent And Benefits All Customers.

20. The High Bridge plant was nearing the end of its useful life.[20]

21. In addition, the Company demonstrated the following added advantages gained as a result of rehabilitating the High Bridge Plant:

- The conversion to natural gas increased capacity by 276.4 MW (almost double), benefiting the entire system.[21]
- The operational flexibility of the new gas-fired units provided improved system reliability, as the Company's system responds to hourly changes in resource and load conditions. This operational flexibility will become

[17] *Id.* at 8-10.
[18] Ex. 3, Larson Direct at 17.
[19] *Id.*
[20] Ex. 10, Engelking Rebuttal at 10-15.
[21] *Id.*

increasingly important as the Company adds future wind generation to its system.[22]

- The conversion allowed the Company to defer investment in new, green-field capacity and energy for several years, which would have been necessary if coal rehabilitation of the site had been selected. Adding capacity at a different location would have required the Company to incur the added cost of acquiring land, developing the infrastructure and building transmission - all of which were already present at the High Bridge site.[23]
- The Company acquired low-cost turbines on the secondary market, and the current estimated cost of a new combined-cycle generating plant is 33 percent higher than the cost of High Bridge.[24]
- Using a different site would have delayed bringing the additional capacity on line.
- Additional capacity within the Twin Cities Metropolitan load center ensures transmission stability and minimized overall transmission congestion, which also helps mitigate MISO Day 2 congestion costs.[25]
- The conversion from coal to natural gas at the High Bridge and Riverside plants and the NOx controls installed at the King Plant are saving the customers between $52 million and $96 million per year in NOx allowances. As a point of reference, the King Plant NOx control device cost approximately $60 million, roughly equivalent to a single year of the otherwise required NOx allowance purchases.[26]
- Emission levels in the Twin Cities Metropolitan service area were improved significantly.

22. The Company also presented evidence as to the significant problems associated with attempting to rehabilitate the coal facility at that site, including the impossibility of expanding generating capacity using coal at High Bridge, due to the

[22] *Id.*
[23] *Id.*
[24] *Id.*
[25] *Id.*
[26] Ex. 11, Rosvold Rebuttal at 15.

limited space for plant expansion and coal inventory.[27] The difficulties of implementing the coal rehabilitation, including significant delays in implementation, would have limited the plant's continued role as an effective contributor to overall system reliability.[28]

23. While the costs of the environmental controls for the coal rehabilitation would have cost approximately one-half the cost of the combined cycle plant: (i) the coal plant would have provided only half of the capacity of the combined cycle plant; and (ii) the cost of the rehabilitation of the High Bridge coal plant would have further increased the cost of that alternative.[29]

24. The decision to convert the High Bridge plant to a natural gas combined cycle facility was prudent.[30]

3. Whether Both The King And High Bridge Projects Provide Needed Additional Capacity For Xcel Energy's Customers.

25. The King and High Bridge projects provide approximately 334 MW of additional capacity and energy, and the King Plant has improved its capacity factor by 15 percent, further increasing the amount of available capacity and energy from the facility.[31]

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[27] Ex. 10, Engelking Rebuttal at 10-15.
[28] *Id.*
[29] *Id.*
[30] The Minnesota Pollution Control Agency ("MPCA") also concluded that the costs of the anti-pollution control equipment and rehabilitation made the coal alternative not cost-effective.
[31] Xcel Energy Initial Brief at 16.

26. It is appropriate for the North Dakota customers to pay their proportionate share of the cost of providing additional capacity and energy needed by the Company's customers. Advocacy Staff agreed that, if the Company needed that additional capacity, then North Dakota customers should pay their proportionate share.[32]

27. The Company's 2000 IRP filing identified the need to add up to 555 MW by 2005, and the need to add up to 715 MW by 2007 (after conservation and load management goals have been subtracted).[33] The 2000 IRP also stated that feasibility studies would be completed in 2001 related to the possible conversion of the High Bridge and Riverside facilities from coal to natural gas.[34]

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[32] Mr. King testified:

> Q. So if, in fact, Xcel Energy needed the capacity it has added to its system, it should be allowed to recover those costs?
>
> A. Yes.
>
> ***
>
> … if that capacity was needed independent of the MERP project, the costs should be allowed. On the other hand, if the capacity was not based on load requirements in 2008, but merely a hedge against future capacity requirement, then I don't think it should be allowed in 2008 because the company has temporarily overbuilt its plant.

Evidentiary Hearing, Vol. III at 652-653. (King).

[33] *See* 2000 IRP, Docket No. E002/RP-00-787, filed July 10, 2000, website: https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=760790 ("*2000 IRP*"), at 5, which states:

> By 2005, NSP expects cumulative resource needs ranging up to 555 and halfway through the planning period, 2007, needs in the range of up to 715 MW.

[34] *Id.* at 7, stating:

> NSP has agreed to continue investigations of the feasibility of converting some of its coal fired plants to natural gas combustion. Within the next year feasibility studies will be completed at High Bridge and Riverside.

28. The Company's 2000 IRP included rehabilitation of the King Plant because that plant was part of the base analysis.[35] Thus, the combined 334 MW of additional capacity provided by rehabilitating the King Plant and the conversion of the High Bridge Plant is consistent with the additional resource needs identified in the 2000 IRP filing.

29. The Company's 2002 IRP filing specifically identified the intention to rehabilitate King, and convert the High Bridge and Riverside Plants to natural gas facilities, and demonstrated the need for the resulting combined additional capacity from all three projects.[36]

30. Figure 3-1 of the 2002 IRP filing presented the results of Xcel Energy's forecast of production capacity requirements compared to existing generation resources and pending generation acquisitions (including the King, High Bridge, and

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[35] *Id.* at 6, stating:

> For the most part this Resource Plan assumes the existing fossil fleet will continue to operate as it does now through the fifteen-year planning period.

Because the King Plant only had a remaining useful life of five years, its rehabilitation was assumed.

[36] *See* 2002 IRP, Docket No.: E002/RP-02-2065, filed December 2, 2002 website: https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=265611 ("*2002 IRP*"), at 52, which states:

> The cycle efficiency improvements will restore approximately 60MW of King's "net dependable" capacity with no increased fuel input.
>
> … This conversion [High Bridge] will … [provide] a total of approximately 515 MW of accreditable capacity, a net increase … of approximately 244 MW. Because of the change from coal to natural gas, this plant's net dependable capacity will also increase to about 515 MW.
>
> This portion of our proposal [for Riverside] will … provide … a net increase in … capacity of about 56 MW.

The combined net dependable addition in capacity for the three plants is in excess of 400 MW. *See* Ex. 4, Larson Direct at 15.

Riverside projects).[37] The data for 2008 on Figure 3-1 demonstrated that when all of the then available and additionally planned capacity were compiled, including the additional capacity provided by King, High Bridge, and Riverside (included in the segment "Emissions Reduction Proposal" of the IRP filing), total resources would barely be adequate to meet demand in 2008 under either a 20 percent or 50 percent confidence level. To meet an 80 percent confidence level, additional new resources were forecasted as being required in 2008.[38]

31. The added capacity from both King and High Bridge is used and useful in serving North Dakota customers.

B. Whether The Company's Expenditures For Emission Control Purposes Were Prudent.

32. Advocacy Staff proposed a disallowance of $438,427, which was believed to be the amount included in the 2008 test year associated with the Company's compliance with the Minnesota mercury control requirements.[39] Advocacy Staff recommended that Minnesota customers should pay those costs premised on the belief that North Dakota customers would be best served if Xcel Energy only complied with current Federal emissions requirements.[40]

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[37] *2002 IRP*, Resource Needs at 27.
[38] Xcel Energy Initial Brief at 19-20.
[39] Ex. 23, King Direct at 7.
[40] Evidentiary Hearing, Vol. III at 639 (King).

33. Advocacy Staff also argued that "to the extent the [mercury] program is anticipating future federal requirements, North Dakota law prohibits NSP's recovery of those costs."[41] That interpretation of North Dakota statutes is incorrect. Neither N.D.C.C. § 49-02-23 nor § 49-06-24 precludes cost recovery for prudently incurred environmental control costs that lower the cost of complying with future environmental requirements.[42] Both Section 49-02-03 and Section 49-06-24 only address the use of environmental externality values. More specifically, they prevent the consideration of environmental externality values in resource planning, and they also disallow cost recovery for higher cost resources selected because of externality values. However, the role of externality values is not an issue in this proceeding.

34. Xcel Energy explained that its strategy is to manage emission regulation costs by anticipating future requirements. The Company has found that, by

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[41] Advocacy Staff Initial Brief at 18.

[42] Section 49-02-23 provides:

> The commission may not use, require the use of, or allow electric utilities to use environmental externality values in the planning, selection, or acquisition of electric resources or the setting of rates for providing electric service. Environmental externality values are numerical costs or quantified values that are assigned to represent either:
> 1. Environmental costs that are not internalized in the cost of production or the market price of electricity from a particular electric resource; or
> 2. The alleged costs of complying with future environmental laws or regulations that have not yet been enacted.

Section 49-06-24 provides:

> The commission may not increase electric rates as a result of actions taken by other states requiring higher cost resources to be built, purchased, or otherwise acquired as a result of the application of quantified environmental externality values, as defined in section 49-02-23, as part of any resource selection process.

anticipating environmental requirements, rather than simply reacting, the Company improves its ability to budget and plan.[43] Using that strategy, the Company has been successful in reducing the cost of compliance.[44]

35. The MERP projects have positioned the Company for compliance with Federal rules that were implemented after the MERP projects were approved, including:

- The Clean Air Interstate Rule ("CAIR");
- Clean Air Mercury Rule ("CAMR"); and
- Best Available Retrofit Technology ("BART") Determinations under the Regional Haze Rule.[45]

36. The MERP projects met Best Available Control Technology ("BACT") for SO_2, NOx and particulate matter ("PM"), which significantly reduces the risk of additional environmental improvements that would otherwise be required because of future plant activities.[46] The resulting savings in NOx allowances equates to $52 million to $96 million per year. In comparison, the King Plant NOx control device cost of approximately $60 million, roughly equivalent to a single year of allowance purchases.[47]

[43] Ex. 11, Rosvold Rebuttal at 16.
[44] Xcel Energy Initial Brief at 22.
[45] *Id.*
[46] Ex. 11, Rosvold Rebuttal at 12.
[47] *Id.*

37. There is no evidence that a "wait to comply" approach would produce savings compared to the Company's strategy for managing emission compliance costs.[48]

38. Minnesota has largely adopted less stringent standards than the federal standards.[49] The one possible exception is with respect to mercury. Regardless of whether the Company is required to comply with the vacated Federal mercury standard, the Minnesota mercury standard, or the expected Federal mercury standard, it would comply by using the same approach, a sorbent injector system. As a result, the capital costs for a mercury removal system would be the same to comply with any of the standards.[50] The only difference would be how much sorbent was required, which is a future Operations & Maintenance ("O&M") cost and is not included *in* the 2008 test year. Thus, the emission control standard used for mercury has had no impact on the test year revenue requirement.[51]

39. The Company also did not incur unnecessary emission costs associated with rehabilitating the King Plant. Even if the Company had delayed the rehabilitation, the emission control requirements would not have been avoided. As the Company explained:

Q. Did Xcel Energy over-control the King plant?

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[48] Xcel Energy Initial Brief at 23.
[49] Ex. 11, Rosvold Rebuttal at 3; Evidentiary Hearing, Vol. I at 293 (Rosvold).
[50] Ex. 11, Rosvold Rebuttal at 9-10.
[51] Xcel Energy Initial Brief at 25.

> A. [W]e did not … . Once you touch the boiler envelope, and that's what we would have to do to rehabilitate that boiler by cutting out the bottom and doing whatever else needed to be done, you are now subject to that regulation and you have to demonstrate that you either reduce your emissions or that you go through the full new source process.[52]

Because the Company was able to reduce the emissions from the King Plant, it avoided the new source review process.[53]

40. The 2008 test year in this proceeding includes neither the equipment nor the sorbent costs related to mercury control. The only additional cost in the test year that resulted from meeting Minnesota requirements is $12,000 incurred for monitoring mercury emissions. That is a necessary compliance cost, and the information provided through monitoring mercury emissions is useful to the Company in designing and managing future state and Federal compliance efforts for mercury.[54] The revenue requirement associated with complying with Minnesota mercury control requirements was approximately $12,000, not $438,427. The Company did not incur additional emission control costs as a result of including the King Plant in MERP.[55] The $438,427 in costs are the North Dakota portion of the environmental costs that are recoverable in Minnesota under a special rate rider for emission control costs, including mercury control costs.[56] Included within the

[52] Evidentiary Hearing, Vol. I at 293-294 (Rosvold).
[53] *Id.* at 286.
[54] Ex. 10, Rosvold Rebuttal at 10-11.
[55] *Id.*
[56] Pursuant to Minn. Stat. § 216B.685.

$438,427 is approximately $200,000 for oxidizing nitrogen equipment at the Sherco Plant (units 1 and 2), approximately $1,000 in engineering work for mercury sorbent injection systems for Sherco unit 3 and the King Plant, and an additional $225,000 in chemical sorbents or reagents to be used at the King Plant for removing sulfur dioxide and reducing oxidizing nitrogen. These were all current 2008 costs, not costs for rehabilitation of King or a future program.[57]

41. The Company is required to comply with the laws of the states in which it operates.[58] The Company's expenses and investments to meet Minnesota environmental requirements satisfy the prudence and used and useful standards[59] because the Company's generation facilities in Minnesota could not be operated if those environmental requirements were not met.[60] Prudence is based on decisions

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[57] Evidentiary Hearing, Vol. I at 291-292 (Rosvold).

[58] In *Northern States Power Co. V. Hagen*, 314 N.W.2d 32, 37-38 (N.D. 1981), the North Dakota Supreme Court said:

> In this respect we cannot overlook that NSP *is required by* the FERC order to pay a fixed wholesale rate for electricity to NSP Wisconsin which includes the amortization of the Tyrone loss.
>
> The PSC has no direct jurisdiction over interstate wholesale rates and we believe it would undermine the supremacy clause and the preemption doctrine for the PSC to indirectly assert jurisdiction over the wholesale rates … .
>
> We conclude that, for purposes of fixing intrastate rates, the Public Service Commission must treat NSP's filed interstate wholesale rates as a reasonable operating expense. (Emphasis added.)

[59] Under general principles of utility law, the "used and useful" standard simply requires (1) that the property be "in service," and (2) that it "be 'reasonably necessary' to the efficient and reliable provision of utility service." *City of Evansville v. Southern Indiana Gas and Electric Co.,* 339 N.E.2d 562, 589-91 (1975); *Public Service Commission v. Diamond State Telephone Co.,* 468 A.2d 1285, 1290 (Del.1983); and Senior *Citizens Coalition Of Northeastern Minnesota v. Minnesota Public Utilities Commission*, 355 N.W.2d 295 (Minn. 1984).

[60] Validly mandated pollution control facilities are routinely considered "used and useful," and thus included in a utility's rate base, even though such facilities do not produce or distribute electricity, or

available to the Company, and the Company cannot operate its facilities unless it meets all applicable requirements.[61]

42. The cost of complying with emission requirements is a cost of doing business and is recoverable from all customers.

C. Whether The Grand Meadow Wind Farm And Transmission Costs For Wind Generation Located In Minnesota Are Reasonable.

43. Advocacy Staff proposed disallowing 25 percent of the cost of the Grand Meadow Wind Farm and 25 percent of transmission costs related to wind generation located in Minnesota, based on the assumption that comparable wind farms located in North Dakota would be 25 percent more efficient and, therefore, 25 percent less costly (a combined disallowance of $159,175).[62]

44. Initially, the Company was required to install wind capacity in Minnesota as a condition of being allowed to install dry cask storage at the Prairie Island nuclear facility.[63] Grand Meadow was part of that wind capacity. Accordingly, the cost of Grand Meadow was a necessary cost of keeping Prairie Island operational and continuing to provide low-cost energy.[64]

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aid in doing so. *See Green v. Pennsylvania Public Utility Commission,* 473 A.2d 209, 214 (Pa.Commw.1984); *Commonwealth Edison Co. v. Department of Local Government Affairs,* 408 N.E.2d 263, 266 (1980), *aff'd,*; *AFL-CIO, Central Labor Council of Vanderburgh, Posey and Warrick Counties v. Southern Indiana Gas and Electric Co.,* 443 N.E.2d 1243, 1247-48 (Ind.App.1983).

[61] Xcel Energy Initial Brief at 27.

[62] Ex. 23, King Direct at 13.

[63] The requirement of an installation in Minnesota has now been repealed, but it was in effect when Grand Meadow was selected.

[64] Xcel Energy Initial Brief at 28.

45. While the Grand Meadow project and other wind generation facilities are located in Minnesota, the projects have been very efficient and provide very low-cost energy. Grand Meadow is projected to achieve a 40 percent capacity factor,[65] in keeping with Advocacy Staff's projection that North Dakota wind generation would have a capacity range of 40 to 50 percent.[66]

46. While the early Minnesota wind projects had capacity factors of 34.7 percent, that capacity factor was a reflection of early technology, not location. The Velva, North Dakota Wind Farm, for example, had a capacity factor of 31 percent.[67] As the Company explained:

> The projected capacity factors in Minnesota are actually quite a bit higher than what has actually been achieved, … and that has to do with the differences in hub heights, that hub heights are getting much taller, that technology is getting better at capturing the wind. For example we now have turbines that very efficiently capture wind at low wind speeds that we couldn't actually do before.[68]

47. A number of other critical factors make Grand Meadow and other Minnesota based wind generation a low-cost resource. In particular, both Grand Meadow and the Buffalo Ridge are located closer to the Company's primary load than a potential North Dakota wind project. Advocacy Staff agreed that: "the closer you are to the load center the better."[69]

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[65] Evidentiary Hearing, Vol. I at 117 (Larson).
[66] Evidentiary Hearing, Vol. III at 660 (King).
[67] Xcel Energy Initial Brief at 30.
[68] Evidentiary Hearing, Vol. I at 217-218 (Engelking).
[69] Evidentiary Hearing, Vol. III at 661 (King).

48. The Grand Meadow project already had Midwest Independent System Operator ("MISO") approval to access the transmission network, allowing the project to go on line in time to meet the Company's needs. The interconnection queue with MISO currently contains over 20,000 MW of wind projects in its area, and it is estimated that it will take many years to study and interconnect those proposed projects. Had the Company sought new wind generation in either Minnesota or North Dakota, the project could not have been brought on-line in time.[70]

49. An additional cost benefit that flowed from the ability to interconnect the Grand Meadow project quickly was the available Federal Production Tax Credit on wind energy, which is set to expire at the end of 2008. This tax credit is worth $20.00 per MWH for the first ten years, or more than 16 percent of the cost of the Grand Meadow project.[71]

50. The Company selects its wind projects using competitive bidding. After the Minnesota legislature removed the requirement to locate additional wind projects in Minnesota, if a North Dakota wind project had bid a lower cost, it would have been selected.[72] All of the evidence supports the conclusion that the existing wind energy was the lowest-cost alternative at the time.

[70] Ex. 10, Engelking Rebuttal at 18-19.
[71] *Id.* at 19.
[72] *Id.*

51. Xcel Energy operates an integrated transmission system and that system is incompatible with isolating generation to serve just North Dakota load.[73] The Company also explained that its existing transmission network between North Dakota and Minnesota is not adequate to serve significant new wind generation for the Company (other utilities with baseload generation in North Dakota can reduce their reliance on that generation when wind generation is available and, thus, are able to use their existing transmission).[74]

52. While installation of separate wind generation serving only North Dakota load is not feasible, Xcel Energy plans to develop wind generation in wind-rich areas throughout its service area, including North Dakota. A primary impediment to date has been the lack of adequate transmission -- a constraint that is being addressed by the CapX Fargo to Monticello project.[75] Xcel Energy recognizes the benefits of diversifying wind resources over as large an area as possible and is affirmatively planning and investing in its system to this end.[76]

53. The record shows that there is no basis in the record to disallow 25 percent or any other portion of the wind generation and associated transmission.

[73] Evidentiary Hearing, Vol. I at 325 (Grivna).
[74] *Id.* at 325-326.
[75] Ex. 10, Engelking Rebuttal at 19.
[76] *Id.* at 30.

D. Whether Refuse Derived Fuel Generation Is Prudent And Benefits All Customers.

54. Advocacy Staff proposed disallowing $173,000 for three Refuse Derived Fuel generation plants that have been in service for many years, based on Advocacy Staff's assumption that they had been added in response to a Minnesota requirement.[77]

55. While the Company is allowed to count these plants (along with preexisting hydro) toward its renewable energy requirements, these projects were not undertaken in response to a Minnesota renewable energy requirement.[78]

56. The record shows that:

- The Red Wing plant, a 20 MW plant, was constructed in 1949 as a coal plant and converted to Refuse Derived Fuel in 1984;
- The Wilmarth plant, a 20 MW plant, was constructed between 1941 and 1948 as a coal plant and converted to Refuse Derived Fuel in 1984; and
- The French Island plant, a 25 MW plant, was constructed as a coal plant between 1940 and 1948 and was converted to burn wood waste and Refuse Derived Fuel in 1986.[79]

57. These facilities have been a reliable part of the Company's integrated system since the 1940s, and were converted to Refuse Derived Fuel before the Minnesota legislature passed any renewable requirements. They were also approved as a part of North Dakota electric rates in its 1992 rate case and its prior rate cases.[80]

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[77] Ex. 23, King Direct at 12.
[78] Xcel Energy Initial Brief at 34.
[79] Ex. 10, Engelking Rebuttal at 21.
[80] *Id.*

58. The Company's Refuse Derived Fuel generation plants are reasonable and prudent resources used to meet the energy and capacity needs of all customers and should be included in the revenue requirement.

V. OPERATING INCOME STATEMENT

A. Whether The Renewable Development Fund Is A Necessary Cost Of Operating The Prairie Island Nuclear Facility.

59. Advocacy Staff proposed disallowing $170,000 in expenses for the Company's Renewable Development Fund ("RDF") because the RDF is a response to Minnesota requirements and should be charged only to Minnesota customers.[81]

60. The lack of a Minnesota specific benefit is reflected in the fact that approximately 20 percent of the total R&D funds have benefited North Dakota organizations.[82] The test year amount of $170,000 representing the North Dakota allocated share of the energy production ("EP") grant payments and a portion of the RDF administrative costs.[83] The test year does not include expenditures related to R&D and Renewable Energy Production Incentives, which are born directly by Minnesota electric retail customers.[84] The Company has not sought recovery of costs that are expected to only benefit Minnesota interests.

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[81] Ex 23, King Direct at 12.
[82] *See* Ex. 21A, Heuer Rebuttal, Schedule 1, which contains additional detail on grant awards to North Dakota based projects.
[83] Ex. 21A, Heuer Rebuttal at 14.
[84] *Id.*

61. The RDF program benefits all customers, because its goal is to improve the efficiency of generation using renewable resources. The Commission has previously allowed cost recovery for research and development costs.[85]

62. The RDF expenses are also a cost of operating the Prairie Island nuclear facility. In exchange for receiving authority to have on-site interim nuclear fuel storage at the Prairie Island nuclear facility (dry cask storage), the Company is required to fund the RDF. The total annual funding of the RDF in relation to the dry casks located at its Prairie Island nuclear facility is $16 million.[86]

63. If the Company refused to provide the required RDF funding, the operation of the two nuclear generating facilities would be impossible, and the Company would be required to replace approximately 1,670 MW of capacity, of which the North Dakota share is 82 MW.[87] The replacement costs of 82 MW would greatly exceed the $170,000 of RDF costs.[88]

64. For these reasons, the Commission should approve cost recovery of the North Dakota share of the RDF fund.

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[85] Xcel Energy Initial Brief at 35.
[86] Xcel Energy Initial Brief at fn. 91, p. 37 (Minnesota legislation passed in 2007 will also require the Company to provide funding of $350,000 per cask located at our Monticello nuclear facility. We expect to be required to fund $3.5 million related to Monticello dry casks in 2008.)
[87] Ex. 21A, Heuer Rebuttal at 14.
[88] Xcel Energy Initial Brief at 37.

B. Depreciation.

1. Separate North Dakota Specific Depreciation Study.

a. Should The Current Rate Case Be Dismissed.

65. In its Initial Brief, Advocacy Staff argued, for the first time, that the rate case should be dismissed because the Company did not perform a North Dakota specific depreciation study.[89]

66. Relying on long-established Commission policy, Xcel Energy filed its rate case using the depreciation rates previously approved by the Minnesota Public Utilities Commission ("Minnesota PUC") and filed with the Commission.[90]

67. The Company did not file a North Dakota specific depreciation study because it operates an integrated system. As such, there is no separate North Dakota system to separately study for depreciation purposes. The generation and transmission facilities benefit all of the Company's customers.[91]

68. The only facilities that could be separated on a jurisdictional basis are the distribution facilities. The Company has always treated the distribution facilities as part of the overall integrated system. Consequently, the Company does not have the necessary property records that could be used to support a standalone North Dakota

[89] Advocacy Staff Initial Brief at 4-6.
[90] Company Reply Brief at 34.
[91] *Id.* at 19.

and Minnesota distribution depreciation rates.[92] Such records would need to be created at a substantial cost.

69. The Commission has, as a matter of formal policy, elected not to independently study depreciation rates for utilities operating in both North Dakota and Minnesota for nearly two decades. In *Otter Tail Power Company Settlement Agreement,* in Docket PU-401-88-374, the Commission's December 20, 1988 *Order* formally established the practice of developing a single depreciation study for use in both North Dakota and Minnesota, but subject to separate review by this Commission (after the Minnesota rates were established). In 1992, the Commission expressly eliminated its separate review of the Minnesota approved depreciation rates stating:

> The intent of the 1988 Order was that the same depreciation parameters approved by the Minnesota Public Utilities Commission be used in both North Dakota and Minnesota. The purpose was to reduce Otter Tail Power Company's regulatory and accounting burden, not add to it. Accordingly, the requirements of the previous order requiring the Commission to review and approve the Minnesota rates are redundant and unnecessary. [93]

Consequently, the Commission vacated that requirement.

70. The identical practice has been in place with respect to the Company.

71. The ratemaking process must operate prospectively. *See Board of Public Utility Commissioners v. New York Telephone Company*;[94] *Montana-Dakota Utilities v. Public*

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[92] *Id.*
[93] *Amended Order,* Case No. PU-401-88-374, June 23, 1992.
[94] 271 U.S. 23, 30-31, 46 S. Ct. 363, 366 (1926).

Service Commission;[95] *Quad County Community Action Agency v. Elkin*;[96] and *Transcontinental & Western Air v. Civil Aeronautics Board*.[97] The prohibition against retroactive ratemaking has its genesis in constitutional principles, and is also embodied in North Dakota statutes. N.D.C.C. § 49-02-03, provides.

> Whenever the commission, after hearing, shall find any existing rates, tariffs, joint rates or schedules unjust, unreasonable, insufficient, unjustly discriminatory or otherwise unreasonable or otherwise in violation of any of the provisions of this title, the commission by order shall fix reasonable rates, joint rates, charges or scheduled to be **followed in the future** in lieu of those found to be unjust, unreasonable, insufficient, unjustly discriminatory, or otherwise in violation of any provision of law.

(Emphasis added.)

72. If the Commission elects to implement Advocacy Staff's recommendation, the Commission will need to do so without dismissing this proceeding. If the rate case were dismissed, it would deny the Company the right to retain the interim rates it was entitled to receive under the Commission's depreciation policies in effect at the time it filed the rate case and interim rates went into effect. That would be a prohibited retroactive application of a new policy requiring a North Dakota specific depreciation study.

73. For the following reasons, the Commission agrees this case should be based on the existing depreciation studies:

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[95] 431 N.W. 2d 276, 280-281 (N.D. S. Ct. 1988).
[96] 315 N.W.2d 665 (N.D. 1982).
[97] 336 U.S. 601, 604, 69 S. Ct. 756, 758 (1949).

- It is consistent with the integrated system used to serve North Dakota customers.
- Advocacy Staff based its arguments for a North Dakota specific depreciation study on statements of its witnesses made during the hearings that a North Dakota specific study could result in lower depreciation expense for distribution plan.[98] The Company did not have an opportunity to present expert testimony to refute these assumptions.[99] The assumption that North Dakota would have a lower depreciation expense than Minnesota is unsupported; and the real potential for shorter North Dakota useful lives for distribution facilities as a result of the harsher, colder, North Dakota winters has been ignored.

74. It is consistent with long-standing Commission practice of using an integrated depreciation study; and, consequently, dismissal of the rate case because the Company did not foresee this change in policy would be prohibited retroactive ratemaking.

b. Whether Existing Regulatory Practices Concerning Depreciation Studies Should Continue.

75. Advocacy Staff proposed that the Company, in the future be required to file a North Dakota specific depreciation study.[100] This is an extension of the request to dismiss this current rate case because of the lack of a North Dakota specific depreciation study.

76. The Company explained that, because it operates an integrated system, the current methodology for allocating and tracking costs is simple and

[98] Evidentiary Hearing, Vol. III at 701-703 (King).
[99] Company Reply Brief at 19-20.
[100] Ex. 24, Majoros Direct at 7.

straightforward. All generation assets, transmission assets, and the vast majority of common and general assets are shared across all jurisdictions.[101] If North Dakota were to order different depreciation rates, that process would need to be abandoned. It would be necessary to establish jurisdiction-specific accounting records for depreciation expense and accumulated depreciation to insure that the appropriate level of depreciation being recovered from North Dakota customers is being properly tracked. As demand percentages change, additional regulatory guidance would be needed to reconcile the inconsistency between jurisdictional specific depreciation rates and system allocated costs.[102]

77. Having a separate depreciation study and North Dakota specific accounting will generate additional North Dakota specific regulatory costs to review the study and implement jurisdiction specific rates.[103] The Company estimates that it would cost $300,000 to develop new property records for distribution based on jurisdictions, a cost that it would seek to recover from North Dakota ratepayers.

78. With the implementation of North Dakota specific depreciation rates, the Company will be required to implement jurisdictional specific accounting to insure that each jurisdictional customer base is equitably treated as to the amount of capital previously recovered and to allow the Company to track the recovery of its capital

[101] Ex. 18, Robinson Rebuttal at 15-18.
[102] *Id.*
[103] *Id.*

investments. Such jurisdictional specific accounting would be more costly and burdensome compared to the current process.[104]

79. There is no reason based on this record to assume that a North Dakota specific depreciation study would not result in higher rates in North Dakota because of its harsh climate.

80. Xcel Energy will continue to provide the Commission all depreciation filings made in Minnesota, as it agreed to do in response to concerns raised during its most recent natural gas case (Case No. PU-06-525), and address any questions or concerns that those filings may cause.[105]

81. There is no evidence that would justify the additional costs and regulatory burdens on both the Commission and the Company that would result from adopting a North Dakota specific depreciation cost study and review process.

2. Depreciation Expense.

a. Whether The Company's Uses Of The Whole Life And Remaining Life Methodologies Are Reasonable.

82. Mr. King, a consultant for Advocacy Staff, recommended that the Company be ordered to cease using the "whole life" methodology for calculating depreciation expense for transmission, distribution and general structure plant assets and to use instead the "remaining life" methodology. The reason for this suggestion

[104] *Id.*
[105] Xcel Energy Initial Brief at 70-71.

is that the remaining life methodology provides a self-correcting mechanism to eliminate excess or insufficient depreciation accruals.[106]

83. Xcel Energy uses whole-life and remaining life methodologies allocated over the full life of the asset for the appropriate types of assets, *i.e.*, transmission plant, distribution plant and general structure plant accounts.[107]

84. The Company has shown that the whole life methodology: (i) is recognized as an appropriate methodology for transmission plant, distribution plant and general structure plant accounts; (ii) is more appropriate for non-production facilities; (iii) is less burdensome to administer than the alternative remaining life methodology; and (iv) both methodologies recover the same cost over the life of the asset. Because the accrual rate under the whole-life methodology is based on the average life of a large group, the difference between accruals for early retirements of individual assets will be balanced by those assets having longer than average lives.[108]

85. The result is that differences in actual experience are largely offset and the group as a whole will be fully depreciated by the time of final retirements. This is the standard method used across the industry to model depreciation for transmission, distribution and general plant assets.[109]

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[106] Ex. 23, King Direct at 19.
[107] Xcel Energy Initial Brief at 39.
[108] Ex. 18, Robinson Rebuttal at 3-4.
[109] Xcel Energy Initial Brief at 40.

86. The Commission has approved the whole-life technique in every rate case since the beginning of Commission regulation in North Dakota. Any potential improvement in cost recovery matching (under the remaining life methodology) is more than out-weighed by the higher burden involved in using that methodology for routine transmission, distribution and general structure plant accounts.[110]

87. The remaining-life technique requires more precision in the estimated life and dispersion of retirements than the whole-life technique. Consequently, its added burdens are justified for the few, unique and high-cost production plants. It is not justified for the transmission, distribution and general structure plant accounts.[111]

b. Whether The Company's Specific Useful Lives Are Reasonable.

88. Advocacy Staff proposed $4,100,000 of adjustments based on proposals to extend the lives of the Sherco Plant, the Prairie Island nuclear facility, and five of the gas peakers beyond the useful remaining lives of the current investment in those plants. Advocacy Staff's recommendations were based on industry averages and were not based on plant-specific analysis.[112]

89. The Company determines the useful lives for generating units based on a detailed and comprehensive evaluation of each unit. The useful lives of transmission,

[110] *Id.*
[111] Ex. 18, Robinson Rebuttal at 5.
[112] Ex. 23, King Direct at 21-26.

distribution and general structure plant assets are based on actual experience and engineering analysis.[113]

90. The remaining life of a plant needs to be determined based on facts related to the particular asset, not the average life of all plants.[114] Using an average of all plants is not an adequate estimate of the service life of a particular plant. An average service life only has relevance if it is applied to all plants, such that, on average, it is accurate. At a minimum, that would require the application of an average service life to all of the Company's generation units, not just to those which have less than average lives.[115]

(i) Sherco Units Remaining Lives.

91. Advocacy Staff proposed increasing the life expectancy of two of the Sherco units (units 1 and 2) from 44 years to 59 years and the third unit from 33 years to 59 years. The proposed life extension for the Sherco units was not based on any plant-specific analysis. Rather, it was based on the assumption that these unique units would have an average useful life.[116]

92. The Company described its use of the remaining life methodology for its generating plants as follows:

[113] Xcel Energy Initial Brief at 42.
[114] *Id.*
[115] Ex. 18, Robinson Rebuttal at 11.
[116] Ex. 23, King Direct at 22.

> Each year, Xcel Energy is required to reexamine the remaining lives of its generating units based on the facts and circumstances surrounding each unit. Some of the components are:
>
> - Fuel and fuel resource changes
> - System capacity requirements
> - Pollution control equipment and environmental standards
> - Major construction projects
> - Major replacement and repair projects
> - Maintenance programs for plant equipment
> - Other related contracts tied to operating life.
>
> When any new production plant goes into service, an initial life is set based on consideration of function (i.e. base load for Sherco, peaking for combustion turbines), fuel and system capacity, along with other factors. In addition, the Company conducts a detailed Integrated Resource Planning study to determine the projected lives of all of its generating units. As part of its annual remaining life update study, the Company also interviews plant management to determine if any conditions in the plant have changed to warrant a change in retirement date for any generating unit.[117]

93. The Company's process is consistent with Advocacy Staff's testimony that the remaining-life methodology "provides a self-correcting mechanism to eliminate excess or insufficient depreciation accruals."[118]

94. Advocacy Staff's proposal does not consider the extensive rehabilitation costs that would be needed to accomplish such a life extension. Mr. Robinson testified that for the Sherco units to have the 25 and 37 year life extensions proposed by Mr. King, many investments would be needed, including: (i) replacement of turbine

[117] Ex. 18, Robinson Rebuttal at 5-6.

[118] Ex. 23, King Direct at 19. It is highly likely that the results of the Company's proposal will be known before setting final rates in this case, and the Company proposes incorporating any approved changes in its compliance filing calculating final rates.

stationary and rotating components at least once on all three units; (ii) replacement of the generator, main, and reserve transformers at least once on all three units; (iii) replacement of the cooling towers at least once on all three units; (iv) replacement of boiler sections on unit 3, and possibly twice on units 1 and 2; (v) replacement of control systems at least twice on all three units; (vi) expansion of ash disposal systems (ash storage ponds and ash landfills); (vii) upgrading of fuel handling and processing equipment; (viii) replacement of selective catalytic reduction equipment would be needed to reduce NO_x emissions; and (ix) replacement of infrastructure (roads, building, communications). All of these rehabilitation projects are included in the Company's capital project plans for the future.[119] All of these rehabilitation projects are included in the Company's capital project plans for the future.[120]

95. Using Advocacy Staff's methodology, the depreciation rate would have decreased significantly during the 2000 to 2007 period. But, as of the date of the actual life extension in 2007, the depreciation rate would need to collect both the remaining uncollected initial investment (the useful life of which ceased in 2005) and the rehabilitation cost. This methodology provides a rate reduction today by shifting the cost recovery responsibility of today's customers to tomorrow's customers.[121]

[119] Ex. 18, Robinson Rebuttal at 11.
[120] *Id.*
[121] Xcel Energy Initial Brief at 47.

96. The Company has supported its useful remaining life determination for the current investments in the Sherco plant. Using an industry average to substantially increase the life of a unique facility is inconsistent with the rationale for using the remaining life methodology advocated by Advocacy Staff and used by the Company for generating units.[122]

97. Consistent with that practice, the Company has a request pending with the Minnesota PUC to extend the lives of several plants:

Unit	Present Retirement Date	Proposed Retirement Date
Sherco 1 & 2	2019	2022
Sherco 3	2020	2022
Blue Lake 1-4	2010	2012
Key City	2009	2012
Granite City	2009	2012[123]

These life extensions should be used by the Company in developing its final rates.

98. The current investment in the Sherco units does not have a useful life of 59 years, and Sherco cannot have a useful life of 59 years without massive new investment. The Company's method for determining the useful remaining life determination for the current investments in the Sherco plant is accepted.

[122] *Id* at 44.
[123] *Id.* at 13.

(ii) Combustion Turbine Production Plant Remaining Lives.

99. Advocacy Staff recommended a life extension for five combustion turbine plans to 45 years, again based on using the average life of all combustion turbine plants. In one case, Advocacy Staff's recommendation results in over a 75 percent increase in the life of a unit.[124]

100. The Company determined the useful lives based on the remaining lives of the current investment in those plants using a comprehensive analysis of each unit.[125]

101. The Company explained that eight of the combustion plant units would need major overhauls before they could have the useful lives proposed by Advocacy Staff.[126] In addition, those units would need to run for 24 consecutive months in the previous five years to avoid triggering new source review from an environmental perspective.[127] If new source review were required, it would not be economical to restore and run these units with the best available control technology. Life extensions for the other units are expected to be addressed through continued aggressive maintenance but would require upgrades of control systems, replacement of inlet silencers and exhaust diffusers, and replacement auxiliary coolers.[128]

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[124] Ex. 18, Robinson Rebuttal at 11.
[125] Xcel Energy Initial Brief at 28.
[126] Ex. 18, Robinson Rebuttal at 12.
[127] *Id.*
[128] *Id.*

102. For the same reasons the Sherco units should not have their lives extended using an average life, the combustion turbine plants should not be extended based on an average life.

(iii) The Prairie Island Nuclear Facility Remaining Life.

103. Based solely on the fact that Xcel Energy is seeking authority to relicense the Prairie Island nuclear facility with the Nuclear Regulatory Commission ("NRC") Advocacy Staff proposes extending the life of Prairie Island by 20 years.[129]

104. The work and expense involved in filing for an extension and actually extending the life of a nuclear plant is massive. In addition, approximately $18,000,000 in capital improvements will be needed to obtain approval of a twenty-year life extension and to meet the NRC license extension requirements.[130] The remaining life methodology determines the remaining life based on existing investments. To extend the life based on future investments without including those investments is "a mismatch between the realizable life and the investment made to realize that life."[131]

105. While the Company is working toward obtaining the necessary license to accomplish a 20-year life extension, a filing with the NRC is not a guarantee of

[129] Ex. 23, King Direct at 23.
[130] Ex. 18, Robinson Rebuttal at 14.
[131] *Id.*

approval and is not the basis upon which a life extension for depreciation purposes should be made.

(iv) The Life Of Overhead Conductors.

106. Advocacy Staff proposed a 40-year life (a 5 year extension) for overhead conductors based on the fact that Xcel Energy has increased it vegetation control efforts.[132] Advocacy Staff also assumed that North Dakota has fewer trees than Minnesota, and consequently, that overhead conductors would have a longer life in North Dakota than in Minnesota.[133] Mr. King's argument, however, was not based on any evidence that overhead conductors located in North Dakota actually have longer useful lives than overhead conductors located in Minnesota.

107. The Company has carefully analyzed the impact of trees and vegetation management on the useful life of it overhead conductors. As Xcel Energy explained, the nexus between vegetation control and useful lives assumed by Advocacy Staff does not exist:

> Very few of the retirements of distribution overhead conductors are caused by trees hitting lines that are preventable by a cyclical tree-trimming program. The root-cause analysis for tree-related outages is tracked by the Vegetation Management Department of Xcel Energy. That Department investigates every outage involving trees and power lines. One of the main objectives of these investigations is to determine whether the outage was preventable or not. Simply stated, a preventable event is an event that could have been prevented if Xcel Energy had performed routine maintenance on the tree in question the day before

[132] Ex. 23, King Direct at 26.
[133] Evidentiary Hearing, Vol. III at 702 (King).

> the event occurred. Non-preventable tree-related outages typically occur from live broken limbs outside of the normal maintenance zone or uprooted trees outside the right-of-way where the Company could not reasonably predict their failure. Since 2002, Xcel's root-cause investigation of the actual events in North Dakota suggests that 80% (40 out of 50) were non-preventable events. In other words, very few of the retirements caused by trees hitting distribution lines are preventable by a more aggressive tree trimming program. Although there are many other positive benefits from focusing more efforts on tree trimming, reducing the level of retirements caused by trees damaging distribution conductors in not one of them.[134]

108. In addition, the assumption that trees are a primary cause of overhead conductor retirements is incorrect. As the Company has shown:

> In reality, non-preventable damage from storms, ice loading and other non-tree clearance issues are the drivers of retirements for overhead conductors.[135]

109. Mr. King, a Consultant for Advocacy Staff, assumed that North Dakota distribution would have a longer useful life than distribution located in Minnesota. There is no evidence to support that assumption, and there are other weather factors that would support a contrary assumption. In addition, the cost of developing a standalone distribution life would be substantial, and the incremental regulatory burden is not justified.

110. The Company's useful life for overhead conductors is based on actual experience and engineering studies, is reasonable, and should be accepted.

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[134] Ex. 18, Robinson Rebuttal at 15.
[135] *Id.*

c. Whether The Company's Methodology For Recovering Retirement Costs Is Reasonable.

111. Advocacy Staff proposes taking the Company's forecasted retirement expense and reducing that expense by the amount of inflation included when forecasting the future removal cost.[136] Under this proposal, rates would be set to recover the cost of retirement as if the assets are retired during the test year.

112. The Company is expected to incur removal costs for all of its production plants and most of its transmission and distribution accounts other than easements and structures as acknowledged by Advocacy Staff.[137] The Company recovers those retirement costs, based on the forecasted retirement costs, over the useful life of an asset. Consequently, retirement costs are recovered using the same straight-line principles as are used to recover the initial investment in the depreciation expense. Both the initial investment and the forecasted retirement costs are recovered in equal amounts in each year of the useful life of the asset.[138]

113. The Company's methodology is used by virtually by all utilities.[139] It is also used by virtually every State Utility Commission.[140] The Company's methodology is supported by 73 years of traditional and accepted depreciation theory and is fully

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[136] *See* Evidentiary Hearing, Vol. III, at 671 (King); *and* Ex. 19, Watson Rebuttal at 7.
[137] Evidentiary Hearing, Vol. III at 634 (King).
[138] Ex. 19, Watson Rebuttal at 12.
[139] Ex. 23, King Direct at 27.
[140] Xcel Energy's legal research suggests that the methodology used by the Company is approved for use in approximately 44 states.

consistent with accrual accounting principles and regulatory matching principles.[141] The Company appropriately described Advocacy Staff's method as a form of pay-as-you-go cost recovery, whereas the widely-accepted current methodology complies with accrual accounting principles.[142] While Advocacy Staff argued that its proposal was also an accrual method, the results of the proposal do not support this position.[143] The cost of retirements increases over time due to inflation. Thus, Advocacy Staff's methodology, which intentionally sets current rates too low to recover the future cost of retirement, is inconsistent with accrual accounting principles.[144]

114. It is undisputed that the assets will be retired at a higher cost in the future.[145]

115. Advocacy Staff proposed using the Company's five-year historical average retirement costs to set rates.[146] The retirement expense that Advocacy Staff would recover in current rates is, by intent, not enough to recover the actual future retirement expense.[147] This methodology is inconsistent with well established accounting principles and shifts current cost responsibility to future customers. The short-term benefit to current customers provided by this methodology (the test year

[141] Ex. 19, Watson Rebuttal at 7.
[142] *Id.*
[143] Xcel Energy Initial Brief at 54-55.
[144] *Id.* at 55.
[145] Ex. 19, Watson Rebuttal at 4.
[146] Ex. 23, King Direct at 32.
[147] Xcel Energy Initial Brief at 55.

reduction is $455,000[148]) is replaced with a higher cost for future customers. Such a shift in cost responsibility to future customers is inconsistent with accrual accounting principles and regulatory matching principles and will not be adopted.

116. The Company prepared a detailed analysis of the same cost shift using an example with ten assets, installed over a ten-year period.[149] Because the assets will have varying useful lives, the Company's methodology recovers more total dollars initially when all of the assets are in use and fewer dollars as the assets retire. In contrast, Advocacy Staff's methodology will recover most of the costs after the majority of the assets have retired.[150]

117. Advocacy Staff's proposal also results in higher investment costs being paid by Xcel Energy's customers. The higher investment cost would occur because of the impact depreciation expense has on rate base. As depreciation expense is paid, it is treated as accumulated depreciation, which is an offset to rate base. Because Advocacy Staff's methodology returns a greater portion of the investment later in the asset's life, the offset to rate base is delayed, increasing the return on investment included in rates.[151]

[148] Ex. 23, King Direct, CWK-7, Schedule 1, page 1.
[149] Ex. 19, Watson Rebuttal at 11-14.
[150] *Id.* at 12.
[151] *Id.* at 16.

118. The Company's methodology for recovering retirement costs is approved. It properly aligns costs with benefits, and reduces the overall cost for customers.

d. Whether Retirement Costs Paid By Prior Customers Should Be Refunded.

119. Advocacy Staff speculates that if the Company were deregulated, it might treat the amounts it has collected for future retirement costs as profit instead of as a future liability.[152] To prevent this outcome, Advocacy Staff offers two alternatives: (i) treat the $14,500,000 as a regulatory liability, with a permanent rate base offset; or (ii) credit the "excess" against the depreciation expense at $1,450,000 per year over a 10 year period.[153]

(i) The Company Will Properly Account For Funds Collected For Future Retirements.

120. The Company is required by State and Federal law to retire certain assets, such as nuclear power plants and buildings that contain asbestos.[154] Advocacy Staff does not propose refunding any of the retirement costs held by the company for required retirements (termed "legal" asset retirement obligations or "ARO").[155]

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[152] Ex. 24, Majoros Direct at 17.
[153] *Id.* at 17 and 21. On a total Company basis, Mr. Majoros claims that the "overcharge" is $342 million ($18 million for North Dakota). That, however, would be for both natural gas and electric operations. The actual non-legal ARO for electric service is $276.4 million. (FERC Form 1 at Pages 204 to 207) http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=11654315. The North Dakota allocation of that amount would be approximately $14.5 million.
[154] Ex. 19, Watson Rebuttal at 21-22.
[155] Xcel Energy Initial Brief at 60.

Advocacy Staff relied heavily on the fact that FAS 143 only requires retirements for AROs and argued that a fundamental change in accounting has occurred, including a change in the treatment of routine plant retirements ("non-legal AROs").[156]

121. FAS 143 is merely a financial reporting tool.[157] It is not a regulatory tool. It was not issued by a utility regulatory agency such as the Commission.[158] Nor does FAS 143 require any refunds.[159] FERC expressly rejected Advocacy Staff's request to change how non-legal AROs are recognized and treated for accounting purposes stating: "we are not convinced that there is a need to fundamentally change accounting concepts at this time."[160]

122. Advocacy Staff and the Company agree: that the Company will incur removal costs for all of its transmission and distribution plant accounts, other than easements and structures;[161] that recent costs of removal of most utility plant has come to exceed the value of salvage material;[162] and that the Company is entitled to recover all prudently incurred retirement costs.[163]

123. To protect against the Company not retiring assets in the future, Advocacy Staff proposed that the Commission "officially" recognize the amounts

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[156] Ex. 24, Majoros Direct at 9-21.
[157] Ex. 19, Watson Rebuttal at 21.
[158] Evidentiary Hearing, Vol. II at 533 (Majoros).
[159] *Id.* at 531 (Majoros).
[160] *See* Ex. 19, Watson Rebuttal at 26 (discussing FERC Order 631).
[161] Evidentiary Hearing, Vol. II at 527 (Majoros).
[162] *Id.* at 528.
[163] *Id.* at 542.

previously recovered by the Company for future retirement costs as regulatory liabilities,[164] which in turn would require the Company to use a present value approach, rather than the current future retirement cost approach in determining rates.[165]

124. The Company already treats these amounts as regulatory liabilities.[166] There is no need for the Commission to officially recognize the amounts already recovered and treated as a regulatory liability.

125. The Company reaffirmed in this proceeding the offer that it made in its recent natural gas rate case (Case No. PU-06-525) to alleviate concerns that it would not retires assets if deregulated. The Amendment to the Settlement Agreement stated:

> Should, at any future date, there be change in regulation or other event that would result in a change in the above-described process [for treatment of retirement costs] the Company agrees to work with the Commission to ensure that any accumulated depreciation amounts for retirement purposes are considered and appropriately addressed as part of that change.

126. Further, the Company is willing to make the same disclosure in its North Dakota Public Utilities Commission Annual Report for electric operations as it subsidiary Public Service Company of Colorado ("PSCo") agreed to in Case No 06S-656G. PSCo agreed to "include a footnote in its future annual FERC Form 2 filings

[164] *Id.* at 534.
[165] *Id.* at 539.
[166] *Id.* at 534.

disclosing the non-legal asset retirement obligation portion of accumulated depreciation for its gas utility operations."[167]

127. These commitments more than adequately address the concern that the Company will unilaterally change its accounting for retirements in the future.

128. Like FERC, the Commission will determine the regulatory treatment for non-legal AROs within its jurisdiction, and nothing has occurred to justify changing the regulatory treatment of routine plant retirements.

(ii) Whether To Refund Previously Collected Retirement Costs.

129. Advocacy Staff proposed amortizing (refunding) the revenues the Company previously recovered, but not yet spent, pursuant to the existing Commission approved methodology that recovers retirement costs based on their future cost. On a total Company basis, Advocacy Staff claimed that $342 million for both natural gas and electric operations ($18 million for North Dakota) has been "over collected."[168]

130. The Company's information shows that the actual non-legal ARO for electric service is $276.4 million.[169] The North Dakota allocation would be

[167] Ex. 19, Watson Rebuttal at 21.
[168] Ex. 24, Majoros Direct at 9-21.
[169] 2007 Xcel Energy FERC Form 1 at pages 204 to 207.
http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=11654315

approximately $14.5 million, to be amortized under Advocacy Staff's proposal at $1.45 million per year over a ten-year period.[170]

131. In the alternative, Advocacy Staff agreed that the Commission could leave the previously recovered retirement funds as a rate base reduction.[171]

132. The proposal is inconsistent with the decision to not use a present value methodology for recovering retirement costs. Under the approved retirement cost recovery methodology there has been no over-recovery to refund.

133. In addition, to reduce current rates by crediting amounts previously collected in accordance with prior Commission authority, only to recover the credited amounts from future customers, would create a large inequity between current and future customers. This proposal is unsupported by established regulatory principles and practices. It is also not in the interest of North Dakota customers.

134. The proposal would also constitute inappropriate retroactive ratemaking as discussed in *Montana-Dakota Utilities v. Public Service Commission*,[172] and will not be accepted.

[170] Xcel Energy Initial Brief at 64.
[171] Evidentiary Hearing, Vol. II at 532 (Majoros).
[172] 431 N.W. 2d 276, 280-281 (N.D. S. Ct. 1988).

C. Whether The Company's Proposed Sharing Of Wholesale Margins Should Be Approved.

1. Asset-Based Margins.

135. Asset-based margins result when the Company is able to sell excess energy or capacity from its generating facilities.

136. Advocacy Staff recommended that 100 percent of the asset-based margins be passed through the fuel clause.[173] Advocacy Staff's justification is that eliminating the incentive could reduce the fuel costs paid by customers.

137. The Company proposed paying 85 percent of those margins to customers through the fuel clause and retaining 15 percent as an incentive.[174] The Company proposed the incentive to more closely align the interest of shareholders and customers, as it attempts to optimize the use of its generation resources in the wholesale market.[175]

138. An effective incentive mechanism can result in lower customer costs.[176] Incentive regulation and the accompanying alignment of shareholder and customer interest is an important policy goal and has previously been encouraged by the Commission. The Commission previously authorized a similar incentive mechanism for Montana Dakota Utilities in Case No. PU-399-03-296.[177]

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[173] Ex. 24, Majoros Direct at 22.
[174] Ex. 6, Krug Direct at 10.
[175] *Id.*
[176] *Id.*
[177] *Id.*

139. In the interest of maintaining an important policy goal, the Commission adopts Xcel Energy's proposal for paying 85 percent of the asset-based margins to customers through the fuel clause and retaining 15 percent as an incentive.

2. Non-Asset Based Margins.

140. Non-asset based trading is the practice of purchasing energy in the wholesale market (other than for retail purposes) and attempting to sell it for a profit. In these transactions, the Company operates as a competitive marketer of wholesale energy, with the potential for economic gains and the risk of losses.[178]

141. Advocacy Staff recommends paying 100 percent of these margins through the fuel clause to the customers.[179]

142. In recognition that this is a non-utility activity with significant risk, the Company proposed sharing 15 percent of the margins with the customers through the fuel clause. The 15 percent reflects the fact that there are very few customer supplied costs associated with this activity and, if the activity were discontinued, there would be no material decrease in costs.[180] The Company further proposed that customers only participate in net aggregate gains, not losses, thus ensuring that customers are not harmed by this activity.[181]

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[178] *Id.* at 12.
[179] Evidentiary Hearing, Vol. II at 548-549 (Majoros).
[180] *Id.* at 489 (Heuer).
[181] Ex. 6, Krug Direct at 16.

143. Non-asset based margins are the result of a voluntary, non-utility enterprise.[182] If the Company is required to pay the entire profit from this risky activity to the customers, with no recovery of losses, there is no reason for the Company to continue the business. A termination of the business would result in no customer benefit.[183]

144. The Company's proposed sharing of 15 percent of the profits from this risky, non-utility business is reasonable and is adopted. This proposal is also consistent with the Commission's historical support for incentives as an effective regulatory tool.

D. Whether The Company's Proposal For Its Pole Inspection And Replacement And Cable Replacement Programs Is Reasonable.

145. Advocacy Staff recommended that the Company's expenses and new investment in the pole replacement and cable replacement programs be recorded to a depreciation reserve, which reserve is intended to reflect the cost of retiring existing facilities, not the costs of new investment.[184] The net effect of Advocacy Staff's recommendation would be to reduce the Company's revenue requirement by approximately $128,000.[185] Advocacy Staff did not challenge either the reasonableness of the programs or the level of costs incurred by the Company.[186]

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[182] Ex. 7, Krug Rebuttal at 3.
[183] Xcel Energy Initial Brief at 50.
[184] Ex. 21A, Heuer Rebuttal at 3.
[185] *Id.*
[186] *Id.* at 5.

146. The Company requested that the expenses and investments in the pole inspection and replacement and cable replacement programs be reflected in accordance with the functions and purposes of those expenses and investments. The Company's approach conforms to the proper treatment under the FERC Uniform System of Accounts ("USOA").[187]

147. The USOA allocates costs into different accounts based upon the nature and type of those different costs. Accounting under the USOA requires that original costs of the electric plant, used by the utility in the electric utility operations, and having an expectation of life in service of more than one year from the date of the installation, be placed into a property account. Sections 101 and 108 of the USOA read as follows:

> 101 Electric plant in service
> A. This account shall include the original cost of electric plant, included in accounts 301 to 399, prescribed herein, owned and used by the utility in the electric utility operations, and having an expectation of life in service of more than one year from the date of installation, including such property owned by the utility but held by nominees.
>
> 108 Accumulated provision for depreciation of electric utility plant
> ……
> B. At the time of retirement of depreciable electric utility plant, this account shall be charged with the book cost of the property retired and the cost of removal and shall be credited with the salvage value and any other amounts recovered, such as insurance.
> ……

[187] *Id.*

E. *The utility is restricted in its use of the accumulated provision for depreciation to the purposes set forth above.* (Emphasis added).

Account 108 (the depreciation reserve account) is clearly intended to reflect the cost of retirement. In contrast, Account 101 (the plant in service account) is the account in which investments are to be recorded.[188]

148. The USOA depreciation reserve account is limited to costs associated with the retirement of a depreciable electric utility plant. Advocacy Staff's recommendation to assign the costs of new poles and cable into the depreciation reserve mis-assigns those costs. In addition, Advocacy Staff's proposal would begin to deplete the Company's facility retirement fund for a non-retirement purpose, creating a shortfall in the retirement account.

149. The Company's proposal is accepted because the costs are reasonable, and the accounting proposed by the Company accurately reflects both the functions that are being performed and the appropriate accounting treatment under the USOA.

E. Whether Xcel Energy's MISO Schedule 16 and 17 Costs Should Be Recovered Through The Fuel Clause.

150. Advocacy Staff recommends that MISO Schedule 16 and 17 costs be recovered through the fuel clause rather than in base rates.[189]

151. The Company accepts that recommendation, which has the effect of lowering the base rate revenue requirement by approximately $532,000 per year.[190]

[188] Xcel Energy Initial Brief at 51-52.
[189] Advocacy Staff Initial Brief at 24.

This change is approved on a prospective basis, to be reflected in final rates, as otherwise it would be very difficult to determine the appropriate amount to recover in interim rates.

152. The Commission finds this recommendation reasonable and accepts the parties' decision.

F. Whether The Company's Proposed Nuclear Refueling Outage Costs Are Reasonable.

153. Advocacy Staff proposed that the Company's nuclear fuel outage expenses be reduced to $811,935,[191] using the first year accounting costs for implementing the deferral-and-amortization accounting methodology.

154. The Company requested recovery of $2,319,262 for nuclear refueling expenses, based on the normalized expense level under the Commission authorized deferral-and-amortization accounting methodology. This amount accurately reflects the normalized level of amortized costs for refueling all three plants.[192]

155. In December of 2007, the Company petitioned the Commission for permission to change the accounting method for costs associated with routine nuclear refueling outages to deferral-and-amortization. The Commission approved the change in accounting method in its Order Changing Accounting Treatment in Case

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[190] Ex. 21A, Heuer Rebuttal at 7.
[191] Ex. 24, Majoros Direct at 23.
[192] Ex. 21A, Heuer Rebuttal at 10-11.

No. PU-07-774, but reserved the issue of the proper cost level to be initially recovered for determination in this rate case.[193]

156. One of the temporary effects of the accounting change was that the expenses during the first year of transition from direct cost accounting to deferral-and-amortization accounting did not reflect normal cost levels because only nine months of amortization associated with Prairie Island Unit 1, and three months of amortization associated with Prairie Island Unit 2 have been reflected in the first year amortization.[194]

157. Mr. Majoros, a consultant to Advisory Staff admitted that the $2,319,262 reflected the normalized amount of the future expenses.[195] He also admitted that, starting in 2009, his proposal would result in a shortfall of approximately $1,500,000 per year for the Company.[196]

158. The possibility of a future reduction in other costs does not justify selecting a cost level for nuclear outage refueling that is clearly below known future cost and, therefore, not representative.

159. The Company's proposal to use a normalized expense of $2,319,262 accurately reflects the future amortization costs associated with nuclear refueling outage expenses, and is accepted.

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[193] *Id.* at 8-9.
[194] *Id.* at 10-11.
[195] Evidentiary Hearing, Vol. III at 556-558 (Majoros).
[196] *Id.* at 558.

G. Whether Private Nuclear Fuel Storage Costs Are Prudent and Should Be Allowed.

160. Advocacy Staff proposed that the Company's private nuclear fuel storage expense be disallowed because: (i) there was no prior approval by the Commission; (ii) the belief that the project is stalled; and (iii) the belief that this project was Minnesota specific.[197]

161. No assertion was made that the costs associated with this program were inaccurately determined or imprudently incurred.[198] Further, it was recognized that spent nuclear fuel has special storage needs, and that those storage needs will continue after the plant has been decommissioned.[199]

162. The Company seeks recover of approximately $190,000 of expenses associated with developing a private nuclear fuel storage facility.[200] In recognition that the ability to store spent nuclear fuel on site at a nuclear facility is limited, the Company, along with seven other utility companies, began developing a potential private storage facility.[201]

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[197] *Id.* at 552 (Majoros).
[198] Ex. 21A, Heuer Rebuttal at 12.
[199] Evidentiary Hearing, Vol. III at 550-551 (Majoros).
[200] Ex. 21A, Heuer Rebuttal at 12.
[201] Ex. 13, Bomberger Direct at 24.

163. Operating a nuclear generating facility provides substantial rate benefits to customers in North Dakota. One of the costs of operating such a facility is the need to store spent nuclear fuel.[202]

164. The Company's costs associated with the program were accurately determined and prudently incurred, and the Company has developed the facility to the appropriate point at this time.

165. The Company's request to recover $190,000 in costs for the private nuclear fuel storage facility is approved because these costs are reasonable and prudent.

H. Whether Charitable Contributions Serve Customers' Best Interests.

166. Advocacy Staff recommended that the Commission deny any recovery of the Company's charitable contributions.[203]

167. The Company seeks recovery of one half ($86,000) of contributions to charities and institutions associated with its electric service territory in North Dakota.[204]

168. The Company has a responsibility to the North Dakota communities it serves to be an active member of those communities and support local economic development and local charities. In 2008, the Company will donate approximately

[202] Ex. 21A, Heuer Rebuttal at 12.
[203] Ex. 24, Majoros Direct at 22-23.
[204] Ex. 21A, Heuer Rebuttal at 15.

$165,686 to charitable organizations in North Dakota, of which $127,567 will be for focus area grants and community grants.[205] These grants are a form of economic development and the Commission has long approved the inclusion of economic development costs in rates.

169. Many of these service areas are small communities with fragile economic infrastructures. It is in customers' best interest for the Company to support these communities.[206]

170. The Company's request to recover one half of its contributions to charities and institutions ($86,000) is approved because these costs are reasonable and prudent.

I. Whether The Company's Incentive Compensation Should Be Capped at 15 Percent Of Base Pay.

171. Advocacy Staff recommended that the cap for cost recovery on the incentive compensation program to be recovered in rates be reduced to 15 percent of base pay.[207] Advocacy Staff believed that a 15 percent cap had been imposed in the Company's most recent Minnesota rate case.

172. The Company requested that the Commission approve its incentive compensation program subject to a cap on the amount that can be recovered in rates set at 25 percent of base pay. This 25 percent limit is in keeping with the Commission

[205] Ex. 21, Heuer Rebuttal, at Schedule 2, Page 1.
[206] Xcel Energy Initial Brief at 82.
[207] Ex. 24, Majoros Direct at 24.

approved settlement in the Company's natural gas rate case, and was recently approved for inclusion in rates in Minnesota.[208]

173. The Company's compensation program provides incentives for its employees to focus upon customer service, safety, reliability, cost reductions and other related matters by conditioning receipt of this incentive compensation on the successful accomplishment of goals related to these areas.[209]

174. Without this program, the total compensation that the Company pays to its employees would not be competitive with other similar companies, and the Company would not be able to attract the type of employees necessary to delivery high quality service.[210]

175. The Company is entitled to recover its prudently incurred costs, and the desire to reduce rates by itself is not an adequate reason for disallowance.

176. The Company's requested incentive compensation program with a cap on the amount that can be recovered in rates set at 25 percent of base pay is approved.

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[208] *Id.* at 16.
[209] *See* Ex. 9, McDaniel Direct at 10-12; Evidentiary Hearing, Vol. I at 182 (McDaniel).
[210] Ex. 9, McDaniel Direct at 9.

J. Return On Equity And Overall Rate Of Return.

177. Xcel Energy and Advocacy Staff agreed to adopt a 10.75 percent return on equity and an 8.8 percent overall rate of return in a Stipulation Agreement dated January 10, 2008.[211]

178. The Commission finds the Stipulation Agreement reasonable and adopts it in this Order.

K. There Is No Basis To Change How Taxes Are Calculated.

179. The Advocacy Staff: "recommends the Commission no longer use the stand-alone approach but, instead, in the future look at consolidated taxes."[212] That is materially different from Advocacy Staff's recommendation in its witness' testimony that the: "Commission should consider placing NSP on alert in this proceeding that it intends to visit the consolidated tax issue in the next rate case."[213]

180. In response to Advocacy Staff's testimony recommending consideration of this issue in its next rate case, the Company filed the following response:

> Q. DID MR. MAJOROS RECOMMEND ANY ADJUSTMENTS TO THE METHOD USED BY THE COMPANY TO CALCULATE ITS INCOME TAX EXPENSE?
>
> A. No. Mr. Majoros did not recommend any adjustment to the methodology used by the Company to calculate its income tax expense, but he did recommend that the Commission "consider placing NSP on alert" that the Commission may consider "the consolidated tax issue in the next rate case."[214]

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[211] Ex. 4, Larson Rebuttal at 30; Ex. 24, Majoros Direct at 21.
[212] Advocacy Staff Initial Brief at 28.
[213] Ex. 24, Majoros Direct at 8.
[214] Ex. 21A, Heuer Rebuttal at 17.

Q. WHAT IS THE COMPANY'S RECOMMENDATION?

A. Mr. Majoros has provided no basis for the Commission to consider any change in its long-standing practice of using the stand-alone method to determine income taxes, which is part of the fundamental regulatory policy of maintaining separation of regulated and unregulated expenses. Thus, there is no basis to increase the number of issues and complexity of a future rate case.[215]

181. The proper treatment of the Company's taxes is a complex factual and policy matter that was fully litigated in the Company's 2005 electric rate case in Minnesota (Docket No. E002/GR-05-1428), where the Company had five witnesses testify on the several related issues. The Administrative Law Judge recommended against using consolidated taxes in setting rates.[216] The MPUC agreed with the Administrative Law Judge,[217] and the Minnesota Court of Appeals agreed with the MPUC on appeal.[218] The Commission needs the same opportunity to fully and comprehensively evaluate the issue before a decision on the merits could be made.

182. The only issue properly before the Commission is whether to alert the Company that it intends to visit the consolidated tax issue in the next rate case.

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[215] *Id.*

[216] ALJ Order (July 6, 2006), https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3176404 at 33-39.

[217] MPUC Order (September 1, 2006), https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3285507 at 21-24.

[218] In the Matter of the Application of Northern States Power Co., 2008 WL 131201, Util. L. Rep. P 26,991 (Minn. App. January 15, 2008).

183. No evidence was presented by Advocacy Staff supporting consideration of a change in the long-standing regulatory practice of using standalone taxes in setting rates.

184. Advocacy Staff's request to accelerate a decision on the merits of using consolidated taxes in the rate setting process is unsupported by any evidence.

185. Including this issue in a future rate case would greatly complicate the initial filing and subsequent testimony for that case without any evidence justifying the effort and, consequently, the recommendation is not be accepted.

VI. RESOURCE PLANNING.

186. Advocacy Staff proposes a resource plan that "should contain only those resources that are required to meet system load and North Dakota's -- not Minnesota's -- environmental and renewable mandates."[219] Advocacy Staff asserts, however, that it is not: "proposing a stand-alone North Dakota system. Rather, King recommends an Integrated Resource Plan that reflects only North Dakota mandates."

187. It is not possible to serve North Dakota customers using an integrated system while also implementing separate resource plans: one for Minnesota that includes King, High Bridge and wind generation located in Minnesota; and another resource plan for North Dakota that excludes these "Minnesota mandates." If

[219] Advocacy Staff Initial Brief at 27.

adopted, Xcel Energy would no longer serve North Dakota and Minnesota using an integrated system.

188. Under Advocacy Staff's proposed state-specific resource plan, presumably North Dakota would not approve any resources associated with perceived Minnesota "mandates" (*e.g.*, according to Advocacy Staff, the excluded resources would include King, High Bridge, and wind located in Minnesota). This would result in the Company having inadequate resources to meet North Dakota's capacity and energy needs. Xcel Energy could not, for example, allocate more of the Sherco units to North Dakota without denying Minnesota its proportionate share of the Sherco units, something that the Company should assume would be unacceptable to the Minnesota PUC. Therefore, the Company would need to acquire additional standalone resources to serve just the portion of the North Dakota load that the Commission did not want served by the integrated system. The end result is that North Dakota customers would no longer be served by the Company's low-cost integrated network. The end result would be higher cost to serve North Dakota customers.[220]

189. The Company proposes establishing a multi-jurisdictional and collaborative planning process.[221] The Company's proposal envisions that meetings

[220] Xcel Energy Reply Brief at 40.
[221] Ex. 5, Larson Rebuttal at 26-27.

between representatives of all State Utility Commissions would occur prior to the Company filing a resource plan.[222]

190. The Company's proposed process would provide the opportunity to consider and discuss differences between States on a constructive and consistent basis.[223] The Company is also open to considering other approaches, and proposed an initial meeting with Commission Staff to begin developing an appropriate process within 30 days of an Order providing direction for such a process.

191. Working to improve the resource planning process is an appropriate outcome of this proceeding. Mandating a change in the resource planning process that would eliminate use of the Company's existing integrated network to meet all of its customers' needs in favor of standalone resources designed to meet each state's system load and policies is not in the customers' interest.

192. Therefore, Advocacy Staff's recommendation is denied in favor of working with the Company to improve the resource planning process, and the Company is directed to begin discussions with Staff within 30 days of this Order.

[222] Evidentiary Hearing, Vol. I at 23 (Larson).
[223] Ex. 5, Larson Rebuttal at 27-28.

From the foregoing Findings of Fact, the Commission makes its:

CONCLUSIONS OF LAW

1. The Commission has jurisdiction over the parties and the subject matter of this proceeding.

2. Xcel Energy is entitled to rates and charges necessary to provide it an opportunity to earn a reasonable rate of return on its North Dakota electric property, used and useful, for the service and convenience of the public in North Dakota.

3. The rates authorized by the Commission herein will provide Xcel Energy with the opportunity to earn a reasonable rate of return on its property, used and useful, for the service and convenience of the public in North Dakota.

4. This order constitutes a final determination of all issues in this proceeding.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

ORDER

1. Xcel Energy may implement a rate increase for service rendered on and after _____, 2008, sufficient to produce a total annual revenue increase of $17,946,000 million.

2. Xcel Energy shall file revised tariff sheets for the Commission approval consistent with the foregoing findings of fact and conclusions of law.

Dated: October 1, 2008

Respectfully submitted,

By _____

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