BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East
Suite 350
St. Paul, Minnesota 55101-2147

MPUC Docket No. E-002/GR-13-868
OAH Docket No. 68-2500-31182

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

PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW OF THE OFFICE OF THE ATTORNEY GENERAL-ANTITRUST AND UTILITIES DIVISION

October 14, 2014

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This matter came for evidentiary hearing before Administrative Law Judge ("ALJ") Jeanne Cochran on August 11, 2014 to August 15, 2014, at the offices of the Minnesota Public Utilities Commission in St. Paul, Minnesota. A total of seven public hearings were held. Public hearings were held on June 23, 2014, in Minneapolis; June 24, 2014, in St. Paul and Woodbury; on June 25, 2014, in Mankato; on June 26, 2014, in Eden Prairie; and on June 27, 2014, in St. Cloud. The ALJ has also received numerous written comments from members of the public.

Aakash H. Chandarana, Alison C. Archer, James R. Denniston, Mara N. Koeller, and Kari L. Valley, Attorneys at Law, Northern States Power Company, doing business as Xcel Energy, 414 Nicollet Mall, Minneapolis, Minnesota 55401; Richard J. Johnson and Patrick T. Zomer, Attorneys at Law, Moss & Barnett, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, Minnesota 55402; and Stephen E. Fogel, Attorney at Law, Xcel Energy Services Inc., 816 Congress Ave., Suite 1650, Austin, Texas appeared for and on behalf of Northern States Power Company ("Xcel" or the "Company").

Ian M. Dobson and Ryan P. Barlow, Assistant Attorneys General, 445 Minnesota Street, Suite 1400, St. Paul, Minnesota 55101, appeared for and on behalf of the Office of the Attorney General, Antitrust and Utilities Division ("OAG").

Julia E. Anderson, Linda S. Jensen, and Peter Madsen, Assistant Attorneys General, 445 Minnesota Street, Suite 1800, St. Paul, Minnesota 55101, appeared for and on behalf of the Department of Commerce, Division of Energy Resources, Energy Regulation and Planning ("Department").

Alan R. Jenkins, Attorney at Law, Jenkins at Law, LLC, 2265 Roswell Road, Suite 100, Marietta, Georgia, 30062 appeared for and on behalf of the Commercial Group.

James M. Strommen, Attorney at Law, Kennedy & Graven, Chartered, 470 U.S. Bank Plaza, 200 South Sixth Street, Minneapolis, Minnesota, 55402, appeared for and on behalf of the Suburban Rate Authority ("SRA").

Pam Marshall, Energy CENTS Coalition, 823 East Seventh Street, St. Paul, Minnesota, 55106, appeared for and on behalf of the Energy CENTS Coalition ("ECC").

Peder A. Larson and Connor T. McNellis, Attorneys at Law, Larkin Hoffman Daly & Lindgren Ltd., 1500 Wells Fargo Plaza, 7900 Xerxes Avenue South, Minneapolis, Minnesota, 55431-1194, appeared for and on behalf of U.S. Energy Services, Inc. on its own behalf and on behalf of an ad hoc group of its industrial, commercial, and institutional customers (collectively, the "ICI Group").

Andrew P. Moratzka and Sarah Johnson Phillips, Attorneys at Law, Stoel Rives LLP, 33 South Sixth Street, Suite 4200, Minneapolis, Minnesota, 55401, appeared for and on behalf of the Xcel Large Industrials group ("XLI").

Samantha Williams, Attorney at Law, Natural Resources Defense Council, 20 North Wacker Drive, Suite 1600, Chicago, Illinois, 60606, appeared for and on behalf of the Natural Resources Defense Council ("NRDC").

Kevin Reuther, Attorney at Law, Minnesota Center for Environmental Advocacy, 26 East Exchange Street, Suite 206, Saint Paul, Minnesota, 55101-1667 appeared for and on behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, the Izaak Walton League – Midwest Office, and the Sierra Club (the "Environmental Intervenors").

Richard J. Savelkoul, Attorney at Law, Martin & Squires, P.A., 332 Minnesota Street, Suite W2750, St. Paul, Minnesota 55101, appeared for and on behalf of the Minnesota Chamber of Commerce ("Chamber").

John B. Coffman, Attorney at Law, 871 Tuxedo Boulevard, St. Louis, Missouri, 63119, appeared for and on behalf of AARP.

Robert Harding, Clark Kaml, Jerry Dasinger, Andrew Twite, Sean Stalpes, Ganesh Krishnan, Dorothy Morrisey, and Jorge Alonso, 121 Seventh Place East, Suite 350, St. Paul, Minnesota 55101, attended the hearings on behalf of the Staff of the Public Utilities Commission ("Commission").

FINDINGS OF FACT

I. PROCEDURAL HISTORY

1. On November 4, 2013, Xcel filed the instant request to increase rates for electric service by $291.2 million.[1] Xcel's proposal consisted of an increase of $192.7 million in 2014 followed by an increase of $98.5 million in 2015.[2] In addition, Xcel's request anticipated "moderating" its rate increase by accelerating the period to return to customers an excess theoretical depreciation reserve, and by applying to its revenue requirement payments from the Department of Energy that are above Xcel's approved decommissioning accrual requirements.[3]

[1] Ex. 25, at 3 (Sparby Direct).
[2] *Id.*
[3] *Id.* at 28. Absent these "rate moderation" proposals, Xcel's requested revenue deficiency is $391.7 million; $273.8 million in 2014 and $117.9 million in 2015. *Id.* at 4.

2. On January 2, 2014, the Commission accepted Xcel's request as substantially complete, suspended the rate increase pending the Commission's investigation into the merits of the request, and established interim rates. The Commission also referred the matter to the Office of Administrative Hearings for a contested case proceeding.

3. On January 28, 2014 Administrative Law Judge Jeanne Cochran ("ALJ") conducted a prehearing conference at the Public Utilities Commission, 350 Metro Square Building, 121 Seventh Place East, St. Paul, Minnesota.[4]

4. The ALJ issued the first prehearing order and protective order on February 14, 2014. In the first prehearing order, the ALJ ordered that petitions for intervention be filed by February 28, 2014; that direct testimony of intervenors be filed by June 5, 2014; that rebuttal testimony of all parties be filed by July 7, 2014; that surrebuttal testimony be filed by August 4, 2014; and that the evidentiary hearing take place on August 11-18, 2014.[5]

5. The initial parties to the proceeding were Xcel, the OAG, and the Department.[6] Petitions to Intervene were also filed by the Commercial Group, the SRA, the ECC, the ICI Group, the XLI, the Environmental Intervenors, the NRDC, the Chamber, the AARP, and Minnesota Power. No party objected to any petition to intervene.

6. The ALJ granted the Petitions to Intervene for the Commercial Group, the SRA, the ECC, the ICI Group, the XLI, the Environmental Intervenors, the NRDC, and the Chamber in two orders dated February 14, 2014, March 5, 2014. The ALJ granted the AARP's Petition to Interven with limitations, and denied Minnesota Power's Petition to Intervene in orders dated March 14, 2014.[7]

7. The ALJ held public hearings in Minneapolis, St. Paul, Woodbury, Mankato, Eden Prairie, and St. Cloud between June 23, 2014 and June 27, 2014, and conducted an evidentiary hearing from August 11, 2014 to August 15, 2014.[8]

8. The parties submitted direct, rebuttal, and surrebuttal testimony consistent with the ALJ's first prehearing order. The parties also submitted initial and reply briefs on September 30, 2014 and October 14, 2014, consistent with the ALJ's first prehearing order.

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[4] *See* First Prehearing Order (Feb. 14, 2014).
[5] *Id.* at 2-3.
[6] *Id.* at 2.
[7] The ALJ allowed Minnesota Power to submit an *amicus curiae* brief of up to 40 pages no later than September 30, 2014. *See* Order Regarding Petition to Intervene of Minnesota Power (March 14, 2014). Minnesota Power did not submit a brief.
[8] The evidentiary hearing was scheduled to last through August 18, 2014, but was completed ahead of schedule.

II. LEGAL STANDARD

9. Xcel has the burden to prove by a preponderance of the evidence that its request to increase rates is just and reasonable.[9] In order to satisfy this standard, Xcel must show that the evidence in this case justifies its request "when considered with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[10] If the Commission agrees with the OAG, the Department, or other intervenors that portions of Xcel's request are unreasonable, then the Commission should deny those portions of Xcel's request.

10. Additionally, even if the Commission finds the OAG or other parties unpersuasive on an issue, Xcel must still produce evidence demonstrating that its request is just and reasonable. In discussing the utility's burden of proof, the Minnesota Supreme Court held that:

> By merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating that it is just and reasonable that the ratepayers bear the costs of those expenses.[11]

11. In addition to showing that it will incur costs, Xcel must prove that it is reasonable for ratepayers to pay for them. Furthermore, if the Commission has doubts about the reasonableness of the rate increase after reviewing all of the evidence presented, those doubts must be resolved in favor of consumers.[12] Xcel has the burden of producing evidence that each portion of its request is reasonable, and Minnesota law requires that Xcel's request be denied in every instance that it has failed to do so.

III. DISPUTED ISSUES

12. The following issues are disputed between Xcel and the OAG:

A. Costs and AFUDC for Prairie Island;

B. Corporate Aviation Expenses;

C. Return on Nuclear Refueling Outage Expenses;

D. Recovery of CWIP and AFUDC;

E. Wind Farm Production Tax Credits;

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[9] Minn. Stat. § 216B.16; *see also* Minn. Stat. § 216B.03.
[10] *Petition of Minnesota Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989), *rev. denied* Apr. 19, 1989.
[11] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722–23 (Minn. 1987).
[12] Minn. Stat. § 216B.03.

F. Interim Rate Refund;

G. Minimum System Study;

H. Classification of Nobles and Grand Meadow Wind Facilities;

I. Classification of Other Production O&M Expenses;

J. Allocation of Lost Revenue from Economic Discounts;

K. Xcel's D10S Allocator;

L. Revenue Apportionment;

M. Revenue Decoupling;

N. Inclining Block Rates; and

O. Residential and Small General Service Customer Charges.

A. COSTS AND AFUDC FOR PRAIRIE ISLAND.

13. Xcel requested recovery of $78.9 million in costs from the canceled Prairie Island Extended Power Uprate ("EPU").[13]

14. The Prairie Island ("PI") plant houses two nuclear reactors; both Unit 1 and Unit 2 are capable of producing 550 MW of electricity.[14] On May 16, 2008, Xcel filed a Certificate of Need ("CON") requesting permission to implement an 82 MW EPU for each Unit at Prairie Island, for a total uprate of 164 MW.[15] The PUC granted Xcel's CON petition on December 18, 2009.[16]

1. AFUDC for Prairie Island.

15. Xcel is required to follow accounting rules established by the Federal Energy Regulatory Commission ("FERC").[17] FERC rules require Xcel to stop accruing AFUC once a project is not viable or ongoing.

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[13] Ex. 45, Table 1, at 11 (Weatherby Direct).
[14] Ex. 48, at 4 (Alders Direct).
[15] *Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant*, Docket No. CN-08-509.
[16] Order Accepting Environmental Impact Statement, and Granting Certificates of Need and Site Permit with Conditions, *Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant*, Docket No. CN-08-509 (Dec. 18, 2009).
[17] Minn. Rules part 7825.0300, subp. 2.

16. Electric Plant Instruction No. 3, part (17) provides that no AFUDC should be collected on projects that are abandoned.[18] Additionally, FERC Accounting Release 5 ("AR-5") indicates that AFUDC should only be accumulated when "activities that are necessary to get the construction project ready for its intended use are in progress."[19] AR-5 also indicates that "no AFUDC should be accrued during periods of interrupted construction unless the company can justify the interruption as being reasonable under the circumstances."[20]

17. FERC also has a series of decisions that establish the principle that AFUDC should continue to accrue only "as long as the project is viable and ongoing."[21] FERC discussed the "viable and ongoing" standard in *Boston Edison Company*, a case in which FERC considered whether to allow Boston Edison Company ("BEC") to recover costs for the Pilgrim II nuclear plant that was canceled. FERC ultimately ruled that BEC should be permitted to accumulate AFUDC until September 1981 "because BEC's decision to continue the project until September 1981 was prudent."[22] Because BEC acted prudently in cancelling the project in September 1981, the project was viable and ongoing until that time.[23] The corollary of FERC's decision in *Boston Edison Company* is that a construction project is *not* viable and ongoing where the utility's decision to continue the project is not prudent.

18. The record demonstrates that Xcel knew that the PI EPU was no longer viable long before the project was cancelled, and that it improperly continued to accrue AFUDC during that time.

19. Xcel filed its CON for the PI EPU on May 16, 2008, and received approval on December 18, 2009.[24] In order to complete the PI EPU, however, Xcel needed additional regulatory approvals from the Nuclear Regulatory Commission ("NRC"). Xcel submitted an application to the NRC in April 2008 to extend the useful life of the PI plant.[25] In addition to the license extension, Xcel also needed the NRC to approve a License Amendment Request ("LAR") for the uprate. Xcel initially assumed that the NRC would grant its license extension in 2010 or 2011, and planned to file its LAR for the PI EPU in mid-2011.[26]

20. Xcel made preparations for the LAR filing throughout 2009 and 2010, but during 2010 Xcel began to learn that the PI EPU would have significant challenges. In the summer of 2010, Xcel discovered that it would be more expensive than anticipated to complete several of the mechanical upgrades and replacements that had been planned. Specifically, Xcel decided that it would no longer pursue upgrades for the high-pressure turbine, the low-pressure turbine, or the

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[18] 7 C.F.R. 1767.16(c)(17).
[19] *See* Ex. 94, LHP-2, Schedule 8 (Perkett Rebuttal).
[20] *See id.*
[21] *Boston Edison Company*, 34 F.E.R.C. ¶ 63023, at 65074 1986 WL 76218 (Jan. 22, 1986).
[22] *Id.* at 65074.
[23] *Id.* at 65074.
[24] *Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant*, Docket No. CN-08-509.
[25] Ex. 48, at 10 (Alders Direct).
[26] *Id.* at 11.

governor valve.[27] These changes reduced the amount of power that could be gained from the EPU – while Xcel claimed in the CON docket that the EPU would generate 164 MW, after these "scope" changes it would generate no more than 132 MW.[28]

21. To get more information about costs for other parts of the project, in the Summer of 2010 Xcel sent out a Request for Proposal ("RFP") for "Major Power Train Equipment (generator rewind, exciter, high pressure turbine, and moisture separator reheaters)."[29] Xcel received all of the RFP responses on October 29, 2010 and had completed its review of the responses by January 2011.[30] According to Xcel witness Mr. McCall, the RFPs indicated that the cost per kilowatt for the PI EPU had increased by more than 20%.[31] At that point Xcel concluded "that it was not possible to cost-effectively implement the level of EPU that was originally anticipated."[32]

22. At the same time that Xcel was learning the PI EPU would never generate the megawatts that had been promised in the CON, it was also learning that it could not complete the project in a reasonable time frame and that regulatory costs would be significantly greater than anticipated. Xcel had assumed it would receive approval for the PI license extension from the NRC in late 2010 or early 2011, but had still not received approval by the second quarter of 2011.[33] After the March 2011 disaster at Fukushima Daichii, the NRC began to increase regulatory requirements for LAR filings such as PI.[34] In order to learn more about the regulatory process, in the spring of 2011 Xcel reached out to the NRC and scheduled a meeting for the summer.[35] As a result of the meeting, Xcel learned that there would be a "delay in [the] initial filing" and "a significant cost increase" of at least $24 million to get approval for the LAR.[36] Xcel also determined that it would not be able to bring the PI EPU to full power until 2018 given the licensing delays from the NRC.[37] Because the license extension from the NRC extended the life of the plants only to 2033, given the new in-service date the EPU could only operate at its full capacity for fifteen years rather than the expected twenty years.[38] Furthermore, after learning about the new NRC requirements, Xcel felt that it no longer had "assurance of a license."[39]

23. In addition to its inability to provide the 164 MW it had indicated in the CON and the additional licensing costs, in the summer of 2011 Xcel was observing a significant reduction in

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[27] Ex. 49, at 23–25 (McCall Direct).
[28] *Id.* at 24. The HP turbine was expected to provide 3.5 MW per unit; the governor valve 2 MW per unit; and the LP turbine 10.5 MW per unit. *Id.* at 24. The total loss was expected to be 32 MW.
[29] *Id.*at 25 (McCall Direct).
[30] *Id.* at 25.
[31] *Id.* at 27.
[32] *Id.* at 25; *see also* Ex. 48, at 13 (Alders Direct).
[33] Ex. 49, at 26–27 (McCall Direct).
[34] *Id.* at 28.
[35] *Id.* at 29; Tr. Evid. Hearing, Vol. 1, at 208 (McCall) (Aug. 11, 2014).
[36] Ex. 49, at 30 (McCall Direct).
[37] Tr. Evid. Hearing, Vol. 1 at 211 (McCall) (Aug. 11, 2014).
[38] *See* Ex. 48, at 4 (Alders Direct).
[39] *Id.* at 30–31.

demand and a decrease in the price of natural gas throughout 2011.[40] At the same time, Xcel was experiencing skyrocketing cost overruns in its Monticello EPU.[41]

24. Despite its claims that the project was still cost effective,[42] Xcel began the process to suspend the project. According to Xcel witness Mr. Alders, the Company began to suspend the program at the time of its "changed circumstances reassessment."[43] During the evidentiary hearing, Mr. Alders testified that this "reassessment" began following the August 18, 2011 meeting with the NRC.[44] Xcel witness Mr. McCall also testified that suspension began "largely after" the NRC meeting;[45] based on that statements, it appears that some part of the suspension began before the NRC meeting. By the end of 2011, the Company has suspended all possible work on the PI EPU.[46]

25. The first time the Commission was informed about the problems with the PI EPU was a single sentence contained within a request for a time extension in Xcel's 2010 Resource Plan docket.[47] Even though Xcel was well into the process of suspending the EPU, the only information it provided to the Commission was that it had "encountered difficulties in the implementation of capacity upgrades at our nuclear plants."[48] Two months later, on December 1, 2011, Xcel provided more information in an Update to the 2010 Resource Plan. It was not until this Update that the Commission learned that Xcel could no longer achieve the full 164 MW uprate, that there would be delays and cost increases in licensing, and that Xcel would not provide more information until a Changed Circumstances filing.[49] Despite the fact that it had begun suspending the PI EPU the previous summer, Xcel did not provide any recommendation about whether to cancel the project.[50]

26. On March 30, 2012, nearly four months after the Resource Plan Update, Xcel filed a Notice of Changed Circumstances in the original PI CON docket.[51] Once again, Xcel declined to take a position on whether the project should continue despite the fact that it had begun suspension in August 2011. As Mr. Alders admitted, Xcel "could have better facilitated a discussion with stakeholders by presenting our own recommendation."[52] Seven months after the

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[40] Ex. 48, at 15 (Alders Direct).
[41] Ex. 49, at 31 (McCall Direct).
[42] *See id.* at 32.
[43] Ex. 48, at 17 (Alders Direct).
[44] Tr. Evid. Hearing, Vol. 1, at 191 (Alders) (Aug. 11, 2014).
[45] Tr. Evid. Hearing, Vol. 1, at 213 (McCall) (Aug. 11, 2014).
[46] Ex. 49, at 33 (McCall Direct).
[47] Letter from James Alders to Dr. Burl W. Haar, *In the Matter of the Petition of Northern States Power Company, a Minnesota corporation for Approval of the 2011-2025 Resource Plan*, Docket No. RP-10-825 (Oct. 7, 2011).
[48] *Id.*
[49] Resource Plan Update, *In the Matter of the Petition of Northern States Power Company, a Minnesota corporation for Approval of the 2011-2025 Resource Plan*, Docket No. RP-10-825, at 7–8 (Dec. 1, 2011).
[50] *Id.*
[51] Notice of Changed Circumstances and Petition, *Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant*, Docket No. CN-08-509 (March 30, 2012).
[52] Ex. 48, at 18 (Alders Direct).

Notice, Xcel filed updated Comments on October 22, 2013, in which it finally recommended that the project be cancelled.[53] On December 20, 2012, the Commission voted to terminate the PI EPU project, and issued an Order on February 27, 2013 concluding that it was in the public interest to discontinue the project.[54]

27. At the time the Commission issued its February 27, 2013 Order, Xcel had known for more than two years that it could not achieve the full 164 MW it had promised in 2008. And it had been twenty months since Xcel confirmed the regulatory delays and decided to suspend the project. During that period, Xcel continued to accrue AFUDC to the detriment of ratepayers.[55]

28. By August 2011, Xcel knew that it could not achieve the generation that it had promised; that NRC delays would require tens of millions in additional regulatory expenses; that even if the project was completed it would have only fifteen years of useful life instead of twenty; and that, based on Xcel's disastrous handling of the Monticello project,[56] there was a real possibility of major cost overruns. Any reasonable utility would have realized at this point that the PI EPU was not viable. In fact, Xcel did determine that the EPU was not viable because it "largely" began to suspend the project after its meeting with the NRC. At that point, the project was not viable and Xcel should have stopped accumulating additional AFUDC.

29. FERC's rules also indicate that a utility should not accumulate AFUDC when a project is not "ongoing."[57] When Xcel began to suspend the project in August 2011, at the latest, the project was no longer "ongoing." The contractor Westinghouse was allowed to complete some deliverables after August 2011, but not because they would provide any ratepayer benefit. Rather, Xcel decided not to cancel the Westinghouse contract because Xcel had negotiated a contract with Westinghouse that included significant termination penalties.[58] By August 2011, the PI EPU was neither viable nor ongoing. According to FERC's rules, at that point Xcel was required to stop accruing AFUDC.

30. Xcel claimed that to FERC's decision in *Boston Edison Company* supported its position.[59] But Xcel ignored the related state regulatory proceeding, in which the Massachusetts Department of Public Utilities ("MDPU") disallowed expenses and AFUDC that had been accrued after Boston Edison Company ("BEC") should have prudently decided to cancel a nuclear construction project. BEC cancelled the construction of the Pilgrim II nuclear reactor in

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[53] Supplemental Filing, *Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant*, Docket No. CN-08-509, at 10 (Oct. 22, 2012).

[54] Order Terminating Certificate of Need Prospectively, *Application to the Minnesota Public Utilities Commission for Certificates of Need for the Prairie Island Nuclear Generating Plant*, Docket No. CN-08-509 (Feb. 27, 2013).

[55] *See* Ex. 372, JJL-2 (Schedules to Lindell Surrebuttal).

[56] Xcel's management of its other EPU at the Monticello nuclear generating plant is now several years late and hundreds of millions of dollars over-budget. *See In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. 13-754.

[57] *Id.*

[58] Ex. 100, at 57 (Clark Rebuttal).

[59] Ex. 94, at 34–35 (Perkett Rebuttal).

September 1981.[60] When BEC asked for recovery of project costs, the MDPU considered whether BEC's decision to wait until September 1981 to cancel the Pilgrim II project was prudent. Many of the facts that led to the Pilgrim II cancellation are similar to this case. For example, like the Fukushima disaster in this case, the Three Mile Island accident occurred during Pilgrim II construction in 1979.[61] And just as in this case, after Three Mile Island, BEC learned that there would be a significant delay and increase in cost in gaining permits and licensing from the NRC.[62] After BEC learned of these challenges, it held a board meeting in June 1980 and decided to "limit expenditures" even though it would not cancel the project and would continue to pursue the licensing requirements.[63]

31. The MDPU concluded that based on the licensing delays and other problems, BEC should have cancelled Pilgrim II in June 1980 because "uncertainty had become intolerably high" and cancellation was the only prudent course of action.[64] The MDPU disallowed all expenditures after June 1980 because BEC had acted imprudently,[65] and its decision was affirmed by the Massachusetts Supreme Judicial Court.[66]

32. The MDPU's decision supports the OAG's recommendation to disallow costs and AFUDC after August 2011. The MDPU concluded that BEC should not recover any costs incurred after it decided to "limit project expenditures" in June 1980.[67] Similarly, Xcel decided to begin a ramp down process following its meeting with the NRC on August 18, 2011. In doing so, Xcel acknowledged that the project was no longer viable, just like BEC did when it began to limit expenditures for Pilgrim II. Once Xcel was no longer actively trying to complete the project, it should have stopped accruing AFUDC.

33. A careful reading of *Boston Edison* also shows that the issues in the case are distinguishable from the facts surrounding the PI EPU, and, in fact, that the reasoning FERC supports disallowing AFUDC for the PI EPU. FERC reached a different decision from the MDPU, in part, because it determined "uncertainty" about demand growth and an error in sales forecasting was insufficient to support disallowance.[68] FERC also found that several factors that led to cancellation had not become known until after 1980. For example, BEC did not learn that NRC would require additional licensing after issuing a permit until 1981.[69] Similarly, the price of oil began to decline significantly in the second quarter of 1981 at the same time that interest

[60] *Attorney General v. Department of Public Utilities*, 455 N.E.2d 414, 420 (Mass. 1983).
[61] *Id.*
[62] *Id.* at 421.
[63] *Id.*
[64] *Id.*
[65] *Boston Edison Company*, 46 P.U.R. 4th 431, 471–74 (Mass. D.P.U. Apr. 30, 1982).
[66] *Attorney General v. Department of Public Utilities*, 455 N.E.2d 414, 421 (Mass. 1983).
[67] *Id.*
[68] *Boston Edison Company*, 34 F.E.R.C. ¶ 63023, at 65067 (Jan. 22, 1986).
[69] *Id.* at 65070.

rates began to increase, which indicated that Pilgrim II would be less competitive against other alternatives.[70]

34. Applying the factors that FERC reviewed in *Boston Electric Company* to the facts surrounding the PI EPU leads to the conclusion that it was prudent to cancel the project in August 2011. FERC found arguments about uncertainty in demand growth to be unpersuasive, but in this case Xcel has affirmatively acknowledged that its updated estimates showed reduced demand growth.[71] Additionally, FERC found it significant that BEC did not know about the increased NRC licensing requirements and the decline in oil prices until 1981, and concluded that once BEC was aware of those factors its decision to cancel the project was prudent. But Xcel had similar information in August 2011, because after the NRC meeting, Xcel knew that there would be significantly increased NRC requirements, and Xcel knew that the price of natural gas was dropping quickly.[72] Each factor that FERC considered in deciding whether BEC's decision was prudent indicate that a prudent utility would have cancelled the PI EPU in August 2011.

2. Costs for Prairie Island.

35. In addition to disallowing AFUDC after August 2011, the OAG recommends that the Commission deny recovery of costs that were incurred after the PI EPU was no longer viable and ongoing. The OAG points out that Xcel continued to make payments to Westinghouse, the contractor, after it decided to suspend the project.[73] The OAG does not dispute the fact that the termination clauses contained in the Westinghouse contract meant that there was little to be gained by cancelling the contract after August 2011.[74] But the OAG disputes the prudence of entering into a contract structured in such a way that ratepayers would continue to pay the contractor in the event the project became imprudent.

36. Xcel has not demonstrated that it was prudent to enter into a contract with Westinghouse that required ratepayers to continue paying for a project that the company determined was imprudent, and these costs are denied.

37. The OAG also discovered that Xcel transferred $9 million from the PI EPU work order to the PI Life Cycle Management ("LCM") work order at the end of 2012.[75] Xcel witness Mr. Weatherby provided an explanation of $5.9 million of the transfers,[76] but Xcel has not provided any explanation for the remaining $3.1 million. The reason the transfers are questionable is that transferring costs from the EPU to the LCM has the effect of removing them from scrutiny in this rate case. The PI EPU was challenged by many parties in this case,[77] and was an issue of

[70] *Id.* at 65070.
[71] Ex. 48, at 15 (Alders Direct).
[72] *Id.*
[73] Ex. 100, at 57 (Clark Rebuttal).
[74] *Id.*
[75] Ex. 371, JJL-2 (Schedules to Lindell Direct); *see also* Tr. Evid. Hearing, at 194:10–11 (Weatherby).
[76] Ex. 45, at 19 (Weatherby Direct).
[77] For a description of the positions of various parties, see Ex. 100, at 48–50 (Clark Rebuttal).

contention in Xcel's last rate case as well. But no party has challenged the PI LCM in this proceeding. Transferring $9 million from the EPU to the LCM has the effect of ensuring that Xcel will earn its regular rate of return on those costs, rather than a lower or no return as suggested by the other parties in this case for the EPU.

38. Since Xcel has not provided an explanation for a significant amount of the transfer, Xcel must provide further information fully explaining this transfer in its compliance filing before it will receive recovery or a return on the funds that were transferred from the EPU to the LCM.

3. Costs That Have Already Been Written-Off.

39. In 2012 Xcel wrote off $10.1 million from its PI EPU, which it claims was necessary to comply with GAAP.[78] Xcel seeks recovery of these funds that were written off.[79]

40. The $10.1 million was written out of Xcel's books and is not recorded anywhere within Xcel's 2014 test year. The write-off is not a valid test year cost, and is not eligible for recovery.

41. Additionally, a review of utility accounting standards provides further illumination on the reason for the write-off. Xcel did provide the accounting rules that led to the write-off. The evidence indicates, however, that Xcel was attempting to comply with FASB 980-360-35-3. Paragraph 35-3 provides that when a utility anticipates that it may not recover a full return on its cancelled investment, "any disallowance of all or part of the cost of the abandoned plant that is both probable and reasonably estimable shall be recognized as a loss."[80] Further, after the utility calculates its expected recovery, any excess costs above that level are to be reported as a loss.[81] FASB also indicates that "a loss shall not be recognized unless it is probable that a loss has occurred and the amount can be reasonably estimated."[82] Based upon these rules, the evidence indicates that Xcel wrote off $10.1 million because it believed that it was unlikely to recover those expenses based on the Commission's past precedent.

42. Xcel claims that its write-off was proper, and should still result in recovery, because its "independent external auditors did not take exception" to the write-off.[83] Xcel's choice of words is significant: while the auditors did not take exception when Xcel wrote-off $10.1 million, Xcel *does not say* that the auditors would approve reversing the write-off after is has occurred. Xcel's request to recover the $10.1 million is essentially a request to "un-write-off," and is absurd from an accounting perspective. Without providing evidence that the auditors would support such a practice, Xcel should not be permitted to use the auditors as a shield for its request to recover costs that no longer exist. Xcel should not recover the $10.1 million because it was written-off years ago and is not on Xcel's books for the 2014 test year.

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[78] Ex. 45, at 26 (Weatherby Direct).
[79] *Id.* at 27.
[80] ASC 980-360-35-3.
[81] *Id.*
[82] ASC 980-360-35-4.
[83] Ex. 47, at 4 (Weatherby Rebuttal).

4. Return On the Cancelled PI Costs.

43. In addition to its request to recover all of the PI EPU costs, Xcel seeks a return on the project even though it has provided no benefit to ratepayers. In direct testimony, the OAG, the Department, and the MCC all proposed that any costs Xcel is permitted should be recovered through amortization with no returns.[84] In order to reach what it believed was a "reasonable compromise," in rebuttal Xcel offered to amortize the project over a 12-year period with no returns.[85] In surrebuttal, however, Department witness Mr. Lusti continued to oppose Xcel's proposal. Mr. Lusti testified:

> I do not support Xcel's proposal . . . since that period of recovery is less than 60 percent of the remaining life of Prairie Island (12/60.3 = 59.1 percent).
>
> Moreover, I conclude that the most appropriate approach that is consistent with the Commission's prior decisions, would be to allow Xcel to recover the costs . . . over the 20.3 years of remaining life of PI, with no return.[86]

At the evidentiary hearing, however, Xcel announced that it had agreed to an alternative approach proposed by Mr. Lusti, in which Xcel would recover the PI EPU costs over a period of 20.3 years with a debt-only return of 2.24 percent.[87]

44. Even though Xcel and the Department have agreed to a debt-only return, the OAG recommends that the Commission follow its precedent and award no return on the cancelled PI EPU. At the time of surrebuttal, the Department agreed that the best course was to grant no return. In discussing his alternative proposal, Mr. Lusti was careful to note that he did not think this debt-only alternative was the right decision. Instead, Mr. Lusti noted, "I conclude that the approach that would be most consistent with the Commission's prior decisions, would be to allow Xcel to recover the costs of the . . . abandoned plant of the 20.3 years of remaining life of PI, with no return."[88]

45. As noted by Xcel witness Mr. Clark, when the Commission allows recovery of cancelled costs it has been "without a return on the asset."[89] When the Commission granted recovery of preliminary costs for Interstate Power and Light's Sutherland plant, it authorized amortization over the expected life of the plant with no return.[90] When the Commission granted recovery of

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[84] Ex. 370, at 44 (Lindell Direct); Ex. 340, at (Schedin Direct); Ex. 437, at 18 (Lusti Direct). The ICI proposed that if Xcel is allowed to earn a return it should be limited to the U.S. Treasury bill rate. Ex. 250, at 12 (Glahn Direct).
[85] Ex. 100, at 51 (Clark Rebuttal).
[86] Ex. 442, at 6 (Lusti Surrebuttal).
[87] Ex. 140, at 1 (Heuer Opening Statement); *see also* Ex. 442, at 6 (Lusti Surrebuttal).
[88] Ex. 442, at 6 (Lusti Surrebuttal).
[89] Ex. 20, at 51 (Errata to Clark Rebuttal).
[90] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. GR-10-276, at 32–33 (Aug. 12, 2011).

the costs of the cancelled Big Stone II plant, it did so with no return.[91] The Commission's practice is supported by sound policy, because it follows the used and useful doctrine that prohibits utilities from earning a return on any projects that are not currently used and useful for ratepayers. The Commission's precedent also strikes a fair balance between ratepayers and shareholders: prohibiting Xcel from earning a return on cancellation costs protects ratepayers from paying for projects that provide no benefit, and protects shareholders for losing the value of their investment.

46. For these reasons, Xcel shall amortize the costs of the PI EPU for 20.3 years with no return.

B. CORPORATE AVIATION EXPENSES.

47. Xcel has reported $1.9 million in jurisdictional corporate aviation expenses and seeks permission to recover 50% of the costs from ratepayers.[92]

48. The Commission has previously authorized Xcel to recover 50% of its corporate aviation expenses. In Xcel's last rate case, however, the Commission ordered Xcel to provide additional information about aviation expenses:

> In the initial filing of its next rate case, the Company shall include more detailed flight data reports (preferably in live Microsoft Excel electronic format) of its corporate jet trip logs for its most recent 12-month operational period. The report, by flight, must identify the charged employee, each employee passenger and his/her assigned operating company, the other passengers on flight and reason for use, and primary purpose for scheduling the flight. The Company shall include information for the calculation of the requested recovery amount of corporate aviation.[93]

49. Xcel has not complied with the Commission's requirement to provide more information, and has not demonstrated that its request to recover aviation costs is reasonable. Specifically, the OAG identified three concerns with Xcel's request: first, Xcel has requested recovery for some flights that provide no benefit to ratepayers; second, the cost per flight that Xcel is requesting recovery of is unreasonable, and; third, Xcel has not provided reasonable business purpose for many of its flights.

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[91] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. GR-10-239, at 12 (Apr. 25, 2011).
[92] Ex. 77, at 2 (O'Hara Rebuttal).
[93] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961, at 53 (Sept. 3, 2013).

1. Flights That Provide No Ratepayer Benefit.

50. In an attempt to comply with the Commission's order requiring it to demonstrate the primary purpose of each flight, Xcel provided a flight log that included a column indicating the business purpose of the flight.[94] For many of these entries, however, the stated business purpose would not provide any benefit for ratepayers and Xcel should not receive any recovery.

51. For example, Xcel lists 33 instances of "Personal Travel," and three additional instances where the person travelling was the spouse of an Xcel employee.[95] OAG recommended that $3,518 in personal travel expenses be disallowed for these flights.

52. Xcel's flight log also includes 91 entries for which the business purpose was either "Investor Relations" or "Shareholder Meeting."[96] Because these flights provide benefits to investors rather than shareholders, the OAG recommended that $8,892 in corporate aviation costs be disallowed for these flights.[97]

53. Xcel's flight log also listed 42 flights for which the business purpose was "Aviation Use."[98] Xcel did not further explain what "Aviation Use" entails. Presumably, those costs are for pilot training or maintaining Xcel's corporate jets. Therefore, the costs are caused directly by Xcel's decision to use corporate aircraft and would not be incurred if Xcel purchased tickets on commercial airlines. The OAG recommended that $4,104 in corporate aviation costs be disallowed for these flights.[99]

54. In response to the OAG's recommendations to remove costs for personal travel, investor benefit, and aviation use, Xcel claimed that it accounted for these requesting that it recover only 50% of the aviation costs it allocated to NSP Minnesota electric.[100] Xcel's methodology, however, is only a blunt instrument to reduce costs across the board, rather than a true review of aviation costs. Investigating aviation costs directly, instead of using such a proxy method, better ensures that ratepayers are only paying for reasonable costs. When the OAG conducted such a direct investigation, it determined that costs related to personal travel, investor benefit, and aviation use were not reasonable costs for ratepayers.

55. The OAG's recommendation that Xcel not recover costs of corporate aviation that do not benefit ratepayers is reasonable.

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[94] Ex. 371, JJL-13 (Schedules for Lindell Direct).
[95] Ex. 370, at 53 (Lindell Direct).
[96] Ex. 371, JJL-13 (Schedules for Lindell Direct).
[97] Ex. 370, at 54 (Lindell Direct).
[98] Ex. 371, JJL-13 (Schedules for Lindell Direct).
[99] Ex. 370, at 54 (Lindell Direct).
[100] Ex. 77, at 8 (O'Hara Rebuttal).

2. Xcel's Cost Per Flight.

56. Each one-way flight for Xcel costs approximately $1,589.[101] Round-trip flights cost more than $3,000.[102] Xcel requests for half of its aviation costs. This would require Minnesota ratepayers to pay more than $1,500 for each round-trip flight, or $750 for a one-way flight, for Xcel's employees across all jurisdictions. The evidence indicates that this is significantly more than it would cost Xcel to purchase commercial tickets for its employees. Analysis by the OAG in Xcel's 2010 rate case demonstrated that an average round-trip ticket from Denver to St. Paul, the most common trip for an Xcel plane, was between $200 and $300.[103]

57. It would be unreasonable for ratepayers to pay for Xcel to fly on a private jet when it costs more than twice as much as an average commercial flight.[104] Instead, the OAG recommends that Xcel's aviation recovery be limited to no more than $300 per flight. Mr. Lindell calculated that, using Xcel's aviation allocators, approximately 1,201 one-way flights were attributable to NSP Minnesota electric.[105] Limiting recovery to the cost of an average commercial flight avoids the inherent flaws of Xcel's proposed 50% adjustment, and would result in a recovery of approximately $360,300.[106]

58. The OAG's recommendation to limit recovery to $300 per one-way flight is reasonable.

3. Flights that have no Business Purpose.

59. In the last rate case, the Commission ordered Xcel to provide the primary business purpose of all of its corporate flights.[107] Xcel produced a flight log with a column indicating the business purpose, but many of the "business purposes" that Xcel claims are vague. For example, Xcel lists thousands of flights as having a business purpose of "Business Area Travel," "Direct Travel," "Manager Travel," or "Xcel Executive Business Travel."[108] While these designations clarify who was on the flight, they provide no information about what the flight was for or why the Xcel employee was traveling. Based on this analysis, the OAG concluded that Xcel had not provided enough detail to satisfy the Commission's order, and the OAG recommended that the Commission deny the costs reported for Business Area Travel, Director Travel, Manager Travel, and Xcel Executive Business Travel.[109]

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[101] Ex. 370, at 50 (Lindell Direct).
[102] *Id.* As discussed by Mr. Lindell, Minnesota ratepayers contribute approximately $518 to each flight in Xcel's system, but it would not be reasonable to use that analysis because it would not be reasonable for Minnesota ratepayers to pay for any flights that are not related to NSP Minnesota.
[103] Smith Direct, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. GR-10-971, at 46 – 47 (Apr. 5, 2011).
[104] Ex. 370, at 51 (Lindell Direct).
[105] *Id.* at 52.
[106] *Id.*
[107] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961, at 53 (Sept. 3, 2013).
[108] Ex. 371, JJL-13 (Schedules for Lindell Direct).
[109] Ex. 370, at 55–58 (Lindell Direct).

60. In response, Xcel argued that the OAG's methodology was not appropriate. According to Xcel witness Mr. O'Hara, "[A] disallowance based on [the OAG's] reasoning is not appropriate since a valid business purpose is a requirement for scheduling a Company aircraft, and the flight logs are not designed to collect detailed descriptions on the passengers' business reason."[110] Mr. O'Hara's argument raises several concerns. Xcel provided the flight logs in order to comply with the Commission's order to provide the primary business purpose of its flights, but Xcel believes that "the flight logs are not designed to collected detailed descriptions on the passengers' business reason."

61. The reason the flight logs do not contain information about the business purpose of a flight is that Xcel has no "systematic process to review the requests" to schedule a flight.[111] Instead, any Xcel employee at the Vice President level or above is allowed to schedule a flight on the company jet at any time.[112] And then, when that employee schedules a plane, he or she is also the person who selects which business purpose code will be recorded in the flight log.[113] Other employees can then add themselves onto the flight and select their own business purpose as well.[114] But Xcel does not have a system to ensure that the reason for the flight is a valid business purpose, or even that employee has selected the correct business purpose code. In fact, no-one ever reviews any of the corporate aviation expenses: According to Mr. O'Hara, there is no process at all to review flight requests and ensure there is a valid business purpose.[115]

62. Xcel's flight logs do not provide enough information to determine the actual reason for scheduling a flight, and do not comply with the Commission's Order or the statutory reporting requirements that apply to every utility.[116] Both the Commission's Order and the statutory reporting requirements make clear that utilities must provide a business purpose for travel expenses that demonstrates that the expenses were reasonable and necessary for the provision of utility service.[117] Xcel's flight logs do not provide enough information to establish that the flights were reasonable or necessary.

63. Xcel's aviation department has additional records about corporate aviation.[118] These records, however, were never provided in discovery, never filed in this case, and no member of the aviation department appeared to discuss them. For these reasons alone, Xcel has not complied with the Commission's order to demonstrate the primary business purpose of a flight. But in addition to the vagueness contained in the flight log, the testimony of Xcel's employees

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[110] Ex. 77, at 6 (O'Hara Rebuttal).
[111] Tr. Evid. Hearing, Vol. 1, at 255 (O'Hara) (Aug. 11, 2014).
[112] Tr. Evid. Hearing, Vol. 1, at 254 (O'Hara) (Aug. 11, 2014).
[113] *Id.* at 256–57 (O'Hara) (noting that employees "schedule themselves on to that plane with different business purposes").
[114] *Id.* at 256 (O'Hara) (Aug. 11, 2014) ("[A]nd then there could be a series of individuals that see that flight is scheduled, and they schedule themselves on to that plane with different business purposes.").
[115] *Id.*
[116] Minn. Stat. § 216B.16, subd. 17.
[117] *Id.*
[118] *Id.* at 257 (O'Hara).

demonstrates that Xcel has no system in place to ensure that its corporate flights are for a valid purpose. As a regulated utility, Xcel has the obligation and burden of proof to ensure that its costs are reasonable. Xcel has failed to do so because it has no system, of any kind, in place to ensure that its corporate aviation expenses are reasonable. For that reason, the OAG's recommendation to deny expenses related to Executive, Director, Manager, and Business Area Travel in the total amount of $309,643 is reasonable.

64. For the reasons set forth above, the ALJ recommends limiting recovery of Xcel's corporate aviation to $300 per flight, removing $309,643 in flights that fail to properly list a business purpose, and removing $16,514 for flights that provide no ratepayer benefit.

C. RETURN ON NUCLEAR REFUELING OUTAGE EXPENSES.

65. Xcel incurs significant expenses at regular intervals to take its nuclear plants offline for refueling. Because its reactors are not all on the same cycle, Xcel's nuclear refueling outage ("NRO") expenses can vary from year-to-year depending on how many reactors are taken offline.[119] For many years, Xcel dealt with this variability by normalizing the expenses over a period of years to create an average expense for a particular test year.[120] In 2008, however, Xcel changed its accounting method and began to defer NRO expenses for the period between outages, which is typically 18 to 24 months.[121]

66. While both the normalization method and the deferral method are able to account for the variability in NRO expenses, the deferral method results in increased costs for ratepayers because Xcel recovers a return while the costs are deferred.[122] Xcel has little incentive to keep NRO costs low because it is allowed to recover a return. For example, while Xcel's standard O&M expenses increased by 1.8% from 2011 to 2013, Xcel's NRO expenses increased by 37% over that same period.[123] From 2008 to 2013, Xcel has earned $16.7 million in returns on its NRO expenses.[124] In other words, Xcel's customers have paid $16.7 million more to compensate Xcel for its NRO expenses than Xcel has actually incurred to refuel its plants.

67. Xcel's practice of deferring NRO costs and earning its full rate of return on the expenses is inappropriate because it allows Xcel to collect a return on normal expenses and creates an incentive for Xcel to increase the scope of NRO expenses. As the ALJ noted in Xcel's last rate case, Xcel should not be allowed to earn its full return on NRO expenses because "the expense is amortized over a relatively short period of time."[125]

[119] Ex. 370, at 45 (Lindell Direct).
[120] *Id.* at 45.
[121] *Id.*
[122] *Id.*
[123] *Id.* at 46.
[124] *Id.* at 45; Ex. 371, JJL-12 (Schedules to Lindell Direct).
[125] Findings of Fact, Conclusions of Law and Recommendations of the ALJ, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961, at 127–28 (July 3, 2013).

68. In order to achieve a better balance for ratepayers, the ALJ recommends that Xcel be permitted to continue using the deferral and amortization method, but that Xcel earn no return on the NRO costs.

D. NUCLEAR REFUELING OUTAGE EXPENSES FOR THE 2015 STEP YEAR.

69. The Commission's Order establishing procedures for multiyear rate plans provides:

> A utility may propose a multiyear rate plan to improve the regulatory process for the recovery of –
>
> A. Costs related to specific, clearly identified capital projects, and
> B. Appropriate non-capital costs.[126]

70. The OAG recommends that reductions in NRO expenses should be included in the 2015 step year. In addition to the upward adjustments it has requested for the 2015 step, Xcel should also include downward adjustments to the 2015 step when there are reductions in expenses or rate base related to capital projects.[127] For example, Xcel included depreciation in its step year because the adjustments are related to capital costs and rate base.[128] The OAG explains that amortized expenses, such as NRO, should be treated similarly.[129] NRO expenses are currently collected through a deferral and amortization method; because they are collected over a period of time, and because Xcel recovers a return on the NRO expenses, they are similar to capital costs should be updated for the 2015 step. NRO expenses are related to capital investments, as required by the Commission's multi-year rate plan order, because they are a necessary part of operating nuclear power plants. As such, they are directly caused by and related to the decision to invest in nuclear generation.

71. Additionally, NRO costs are comparable to other investments because Xcel "earns a return on its NRO expenses just like it does for other capital projects."[130] Xcel witness Mr. Greg Robinson testified that Xcel considers its return on NRO expenses to be "a return on rate base."[131] Mr. Robinson confirmed at the evidentiary hearing that NRO expenses are part of rate base.[132] Because NRO expenses are in rate base, they are related to capital projects and should be updated for the 2015 step year. Furthermore, as noted by Department witness Ms. Nancy

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[126] Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utility Division's Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19*, Docket No. E,G-999/M-12-587, at 12 (June 17, 2013).
[127] Ex. 372, at 6 (Lindell Rebuttal) (noting that "step increases include both capital costs and depreciation expense for the second year of a multi-year rate plan").
[128] *Id.* at 6.
[129] *Id.* at 6; *see also* Ex. 429, at 65 (Campbell Direct).
[130] Ex. 372, at 6 (Lindell Rebuttal).
[131] Tr. Evid. Hearing, Vol. 2, at 101 (Robinson) (Aug. 12, 2014).
[132] *Id.*

Campbell, Xcel "will not incur the higher 2014 amortization outage expense in 2015, so it is unreasonable for ratepayers to pay for this higher 2014 amount in 2015."[133] For the foregoing reasons, the OAG recommends a $5.5 million adjustment for the 2015 step year to represent a reduction in NRO expenses.

72. The ALJ finds the OAG's reasoning persuasive, and recommends a downward $5.5 million adjustment to the 2015 step year.

E. Construction Work in Progress and Allowance for Funds Used During Construction.

73. The record in this case demonstrates that Xcel's use of construction work in progress ("CWIP") and allowance for funds used during construction ("AFUDC") leads to an unnecessarily high return for shareholders. To correct these problems, the OAG recommends that the Commission order several changes to Xcel's CWIP and AFUDC practices. First, the OAG recommends that CWIP should not be included in rate base because Xcel's practice of capitalizing AFUDC provides shareholders with sufficient return on financing costs. Second, the OAG recommends that the Commission modify Xcel's unreasonably high AFUDC rate. Finally, the OAG recommends that Xcel be permitted to accumulate AFUDC only on projects that cost more than $25 million.

74. In Xcel's last rate case the Commission recognized some concerns with Xcel's CWIP and AFUDC practices and ordered Xcel to provide further information:

> In the initial filing in its next rate case, Xcel shall provide evidence of FERC's accounting requirements for CWIP/AFUDC and demonstrate that it has met the FERC requirements. It shall also address whether a minimum dollar level should be set for projects placed in CWIP.[134]

FERC's requirements for CWIP and AFUDC can be categorized as either accounting or ratemaking requirements.[135] The significance of the distinction is the Commission's rules require Xcel to follow FERC's accounting requirements, such as the method used to calculate AFUDC.[136] But Xcel is not required to follow FERC's ratemaking policies that determine whether and how much CWIP to include in rate base. For example, Xcel's current practice deviates from FERC's ratemaking practice of including only 50% of CWIP in rate base.[137] In contrast to the accounting requirements, the Commission has full discretion to establish different ratemaking policies that strike a better balance between ratepayers and shareholders.

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[133] Ex. 429, at 66 (Campbell Direct).
[134] *See, e.g.*, Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961, at 9–10 (Sept. 3, 2013).
[135] Ex. 373, at 3 (Lindell Surrebuttal).
[136] *Id.*
[137] *See* Ex. 371, JJL-5 (Schedules to Lindell Direct).

1. Including CWIP in Rate Base and Accruing AFUDC.

75. The traditional rule of utility regulation is that utilities are only permitted to include capital projects in rate base, and therefore earn a return, on those projects that are "used and useful."[138] Utility property is used and useful when it (1) is "in service" and (2) is "reasonably necessary for the efficient and reliable provision of utility service."[139] Minnesota law provides that one limited exception to the used and useful rule that the Commission may consider is the use of CWIP and AFUDC to permit the utility to recover the financing costs for construction projects.[140] The purpose of AFUDC, and the related practice of including CWIP in rate base, is to "recognize the need for financing large projects," and not to "provide a rate of return on projects that are not used and useful in the provision of service."[141]

76. Xcel's current practices do more than recognize the costs of financing construction projects because they grant a current return on a portion of construction costs in addition to allowing the utility to capitalize its financing costs.

77. Xcel currently recovers its financing costs through a complex process:[142] first, all costs for CWIP are included in rate base and earn Xcel's full rate of return, which Xcel believes should be 7.64 percent;[143] second, Xcel capitalizes financing costs on the balance of CWIP at the AFUDC rate, which Xcel argues should be 6.792 percent, and earns a full return on the AFUDC costs once they are transferred to in-service accounts;[144] and third, Xcel includes the amount of AFUDC as an offset on its income statement.[145] This method provides Xcel a current return on projects that are not used and useful equal to the difference between the rate of return and the AFUDC offset, *and* allows it to capitalize its financing costs and earn its full rate of return on them after they become used and useful. This system places an unreasonable burden on ratepayers.

78. The record in this case does not demonstrate that Xcel requires a current return in order to attract investors, or that such a policy would be fair or reasonable for ratepayers. The OAG recommends that CWIP be removed from rate base so that Xcel does not earn a current return on projects that are not used and useful. To avoid double counting, the OAG also recommends that

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[138] Findings of Fact, Conclusions of Law and Recommendations of the ALJ, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961, at 15–16 (July 3, 2013). The ALJ's Findings 49–85 were adopted by the Commission. Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961, at 19 (Sept. 3, 2013).
[139] *In re Request of Interstate Power for Authority to Change its Rates for Gas Service in Minnesota*, 559 N.W.2d 130, 133 (Minn. 1997).
[140] Minn. Stat. § 216B.16, subds. 6–7.
[141] Ex. 373, at 5 (Lindell Surrebuttal).
[142] Ex. 94, at 16–17 (Perkett Rebuttal).
[143] Ex. 30, at 26 (Tyson Direct).
[144] Tr. Evidentiary Hearing, Vol. 3, at 208 (Lindell) (Aug. 13, 2014).
[145] *See generally* Ex. 94, at 16–17 (Perkett Rebuttal).

the corresponding AFUDC offset be removed from the income statement. The OAG's recommendation is balanced because it would ensure that ratepayers are not paying Xcel a return for projects that are incomplete. At the same time, the OAG's recommendation would continue to allow Xcel to recover financing costs by capitalizing AFUDC and earning its full rate of return after projects are used and useful.

79. Xcel witness Ms. Perkett responded to the OAG's balanced approach by claiming that it would necessarily require removing short-term debt from Xcel's weighted cost of capital.[146] Ms. Perkett claims that, according to FERC rules, "if CWIP is excluded from rate base, the short-term debt should also be excluded from the capital structure."[147] But Ms. Perkett provides no authority for her claim. It is true that FERC does not include short-term debt in its cost of capital calculation, but FERC does not do so *because* of the AFUDC calculation. Xcel produced no evidence to support this claim that FERC's short-term debt policy is related to its policy on CWIP. Xcel also did not provide any reasoning supporting the argument that removing short-term debt from the cost of capital would properly balance the interests of ratepayers and shareholders. More importantly, the Commission has the authority to depart from FERC's rules on this issue because it is an issue of ratemaking rather than accounting. Regardless of FERC's ratemaking policy, in Minnesota utilities include short-term debt in their cost of capital. Xcel's ratemaking approach to CWIP and AFUDC results in excessive returns for shareholders and unreasonable rates for ratepayers. Allowing AFUDC, without also allowing a current return on CWIP, is sufficient to give investors the opportunity to recover the costs of financing construction projects. The OAG's recommendation reaches a more balanced result that protects ratepayers while still recognizing Xcel's financing costs.

2. Xcel's AFUDC Provides an Excessive Return for Investors.

80. Xcel's AFUDC rate also overstates the costs of financing construction projects and provides an unreasonable return to investors. In contrast to the ratemaking policy discussed above, FERC's method for calculating AFUDC is an accounting requirement that Xcel must follow. FERC's Electric Plant Instruction 3(a)(17) ("the Instruction") provides the accounting rule for calculating the AFUDC rate as follows:

> (17) *Allowance for funds used during construction* (Major and Nonmajor Utilities) includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

[146] Ex. 94, at 23–24 (Perkett Rebuttal).
[147] *Id.*

(a) The formula and elements for the computation of the allowance for funds used during construction shall be:

$A_i = s(S/W)\ d(D/D\ P\ C)(1-S/W)$
$A_e = [1-S/W][p(P/D\ P\ C)\ c(C/D\ P\ C)]$
A_i=Gross allowance for borrowed funds used during construction rate.
A_e=Allowance for other funds used during construction rate.
S=Average short-term debt.
s=Short-term debt interest rate.
D=Long-term debt.
d=Long-term debt interest rate.
P=Preferred stock.
p=Preferred stock cost rate.
C=Common equity.
c=Common equity cost rate.
W= Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs (See General Instruction 25) related to plant under construction.[148]

81. The formula instructs a utility to calculate its AFUDC rate calculating a weighted average of short-term debt followed by a mix of long-term debt and equity. But the text of the Instruction also indicates that AFUDC should only include "the net cost . . . of borrowed funds used for construction purposes and a reasonable rate on other funds *when so used*." Therefore, it is only appropriate to include non-debt sources of funds when a utility can demonstrate that it has actually been used to fund construction projects. Xcel has not presented any evidence that it has raised equity for construction projects in this case, so it is not appropriate to include equity in the AFUDC rate calculation.

82. Instead, the OAG recommends that AFUDC be calculated using a blend of short-term and long-term debt, resulting in an AFUDC rate of 2.62 percent.[149] This modified calculation is reasonable given that Xcel has not demonstrated that it has used equity for construction purposes, and is also appropriate because Xcel has substantial cash flow from operations. Additionally, Xcel has access to low-cost cash when it collects excess interim rate revenue.[150] This excess interim rate revenue is available to invest in capital projects.[151] Some of that cash flow should be used to finance construction projects, rather than using equity which leads to increased financing costs for ratepayers.[152]

[148] 18 C.F.R. 101 (emphasis added).
[149] Ex. 370, at 28 (Lindell Direct).
[150] Tr. Evid. Hearing, Vol. 3, at 220–221 (Lindell) (Aug. 13, 2014).
[151] *Id.*
[152] Ex. 370, at 22–23 (Lindell Direct).

83. Xcel witness Ms. Perkett responded to the OAG's recommendation by arguing that it violated FERC's accounting rules.[153] But Instruction 3(a)(17) does not mandate that utilities must use the formula described in paragraph a. Rather, FERC mandates that utilities may not use a rate greater than the formula. Because the Instruction only establishes a maximum AFUDC rate, the Commission may authorize a different formula for calculating AFUDC as long as it does not exceed the formula described in the Instruction. Moreover, Xcel has the burden of proving that its AFUDC rate results in just and reasonable rates for ratepayers, but Xcel has provided no analysis to demonstrate that its formulaic application of the maximum allowable rate is preferable to using a different rate. Given that Xcel has not provided any explanation of why its rate is more reasonable than any other rate and Minnesota law requires "any doubt as to reasonableness should be resolved in favor of the consumer,"[154] the ALJ recommends that Xcel be authorized a return of 2.62 percent on its AFUDC.

3. AFUDC for small Projects.

84. In Xcel's last rate case, the Commission ordered Xcel to "address whether a minimum dollar level should be set for projects placed in CWIP." [155] In its initial filing, Xcel provided some background information on AFUDC but did not include any discussion of whether it would be appropriate to set a minimum dollar level for CWIP beyond the conclusory statement that it believes its current practices provide a "balanced approach."[156] OAG witness Mr. Lindell, however, testified that allowing Xcel to accumulate AFUDC on projects that cost less than $25 million was unreasonable because Xcel does not need to finance projects that are low in cost.[157] Because such smaller projects can be financed with cash recovered through rates, including excess interim rates,[158] Xcel does not incur any financing costs and it would be unreasonable to collect them from ratepayers. AFUDC is not necessary to find a proper balance between ratepayers and shareholders for those projects, and for that reason the OAG recommends that Xcel not accumulate AFUDC on projects under $25 million.

85. Utilities in other states are fully able to provide reliable electric service to millions of customers while operating under AFUDC caps similar to the one proposed by the OAG. For example, utilities in the state of Florida are only permitted to accrue AFUDC on large projects that are in excess of 0.5 percent of rate base.[159] Additionally, Florida rules prohibit utilities from

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[153] *See* Ex. 94, at 28 (Perkett Rebuttal).
[154] Minn. Stat. § 216B.03.
[155] *See, e.g.*, Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961, at 9–10 (Sept. 3, 2013).
[156] Ex. 92, at 60–61 (Perkett Direct).
[157] Ex. 370, at 28 (Lindell Direct).
[158] For example, in Xcel's 2012 rate case the Company collected more than $130 million in excess interim rates, which provided a significant source of low-cost capital for the before it was returned. Compliance Filing – Interim Rate Refund Report, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. 12-961 (Feb. 27, 2014).
[159] Fla. Admin. Code Ann. R. 25-6.0141.

accumulating AFUDC on any projects that will be completed within one year regardless of their cost.[160] The Florida rule provides a useful illustration that other states have caps on AFUDC similar to the one the OAG has proposed.

86. Xcel responded to the OAG's recommendation by arguing that the "consequence of [the] proposal is that the Company would under-earn [its] allowed cost of equity."[161] The very concept of the used and useful principle, however, is that a utility should not earn its allowed rate of return, or its cost of equity, on a project until the project is used and useful. Based on its statements, it appears that Xcel views AFUDC as an opportunity to avoid the used and useful principle. But AFUDC is a limited exception that exists only for the purpose of allowing a utility to recover its financing costs, not to allow Xcel to earn a current return on construction that is not used and useful.[162]

87. Providing AFUDC on lower cost projects also conflicts with the policy goals of AFUDC. The purpose of allowing Xcel to accumulate AFUDC is to offset the risk for major capital investment projects that require significant financing and will require many years to complete. In order to balance the risk that Xcel bears for not earning a return on its financing costs during construction, the Commission has allowed Xcel to accrue AFUDC. But when the cost or duration of the construction projects is lower, Xcel does not bear as much risk for providing financing. Consequently, the ALJ recommends establishing a cap of $25 million on projects that accumulate AFUDC.

F. WIND FARM PRODUCTION TAX CREDITS.

88. Xcel receives wind farm production tax credits ("PTCs") based on the production of its wind generation facilities.[163] In its past rate cases, Xcel has included the estimate of PTCs it expects to receive, and then used the RES rider to true-up actual PTC levels.[164] In its initial filing, however, Xcel failed to incorporate PTCs for the Pleasant Valley and Border Winds wind farm projects that are expected to begin operating in 2015.[165] The Department and the OAG recommended an increase in revenues of $11,093,000 in the 2015 step year to represent the PTCs that Xcel will receive for the two new wind farms, subject to a true-up in the RES rider.[166] Xcel agreed with the proposal of the OAG and the Department in Rebuttal.[167] The ALJ recommends that Xcel's revenues in the 2015 step year be increased by $11,093,000 to represent the PTCs.

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[160] *Id.*
[161] Ex. 94, at 23 (Perkett Rebuttal).
[162] Ex. 370, at 5 (Lindell Direct).
[163] Ex. 372, at 4 (Lindell Rebuttal).
[164] Ex. 429, at 40 (Campbell Direct).
[165] *Id.*
[166] Ex. 372, at 5 (Lindell Rebuttal); Ex. 429, at 41 (Campbell Direct).
[167] Ex. 97, at 7 (Robinson Rebuttal).

G. INTERIM RATE REFUND.

89. Commission rules require Xcel to refund ratepayers the difference between the interim rates it collected and the final rates approved in this proceeding.[168] When Xcel returns its excess interim rates, it is required to provide interest at the prime interest rate.[169] But in this case, just like in Xcel's last case, limiting the interest on the interim rate refund to the prime interest rate would be unfair for ratepayers. Instead, the OAG recommends that Xcel provide interest on the interim rate refund at its full rate of return.

90. The Minnesota Rules require a variance from a Commission rule, such as the rule setting the interest rate for excess interim rates, to be granted when three requirements are met: "(A) enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule; (B) granting the variance would not adversely affect the public interest; and (C) granting the variance would not conflict with standards imposed by law."[170] In Xcel's last rate case, the Commission ruled that each of these requirements had been satisfied. The Commission stated:

> The Commission agrees with the Department, the OAG, and the Chamber that ratepayers are affected by the interim refund rule, and that enforcement of the rule without a variance would impose an excessive burden upon them. The Company's final rates established by this order are substantially lower than the company's interim rates. Ratepayers have been paying higher rates premised on the Company's initial request for a 10.7% increase in rates, effectively lending the Company the difference between interim rates and final rates. Further, the magnitude and frequency of the Company's interim rate over-collection over successive years has a cumulative effect on ratepayers.
>
> The utility has much greater control than ratepayers over whether, when, and how much ratepayers must borrow from or lend to the utility. The Company acknowledges that the interest required by the rule is paid in recognition that the Company had use of funds while interim rates were in effect. The ALJ in Finding 846 identified one circumstance where, when the positions are reversed, the Company imposes a substantially higher rate of interest on ratepayers; the Commission commonly sets carrying charges at the Company's authorized rate of return. Additionally, the prime rate is at historically low levels to accommodate a federal monetary policy that was not anticipated when the interim rate refund rule was adopted.

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[168] Minn. Rules part 7825.3300.
[169] *Id.*
[170] Minn. Rules part 7829.3200, subp. 1.

> Not only does it serve the public interest to recognize this disparity in borrowing costs, but in this case, the rule's low interest rate relative to the Company's authorized rate of return constitutes an excessive burden on ratepayers as captive lenders. Low-income households may particularly suffer hardship when interim rates are over-recovered, and ratepayers generally cannot replace the money the Company borrows at near the prime rate. To impose this hardship in light of the magnitude of this and other recent interim rate over-collections would be an excessive burden. The Commission finds that the first element of Rule 7829.3200 is met.
>
> The second element—no adverse effect on the public interest—is met because it serves the public interest to promote greater equity between utility and ratepayer borrowing costs and to further discourage overstatement of interim rate requests.
>
> The Commission also finds that the third element of the variance rule—no conflict with any other legal standard—is met. The other applicable legal standard, Minn. Stat. § 216B.16, subd. 3, states that the refund of interim rates shall be at the rate of interest determined by the Commission.[171]

91. Each part of the Commission's reasoning from the last case applies to this case as well. Xcel has requested the largest rate increase in the history of the state, and it was granted an interim rate in accordance with that request. But based upon the challenges presented by the OAG, the Department, and other intervenors, and the concessions that Xcel has made, it is very likely that Xcel's final rate will be substantially lower than the interim rate. As Department witness Mr. Lusti noted, "[T]here's a similarity between the last case and this case . . . in that there is a large increase and a good percentage of that increase was being requested by the Department not to be granted."[172] Given the magnitude and frequency of Xcel's rate increase requests, it is unfair to grant the Company access to low cost funds from ratepayers through the interim rates. To do so would impose an excessive burden on ratepayers. And, just as the Commission found in the last case, a variance from the prime rate would not adversely affect the public or conflict with any existing law.[173]

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[171] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. GR-12-961, at 38 (Sept. 3, 2013).

[172] Tr. Evid. Hearing, Volume 5, at 80–81 (Lusti) (Aug. 15, 2014).

[173] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. GR-12-961, at 38 (Sept. 3, 2013).

92. In the last case, the Commission concluded that balance between shareholders and ratepayers could be achieved by setting the interim refund interest rate at the Company's rate of return,[174] and the OAG recommends the same treatment in this case. The Commission stated:

> [Xcel's rate of return] appropriately balances the interests of ratepayers, the utility, and the public. The utility's overall cost of capital represents the cost of alternative sources of utility funds, weighted for the utility's reliance on those sources. Returning borrowed interim rate funds to ratepayers at this rate most equitably compensates ratepayers for forgone opportunities had they not been compelled to lend money to the utility, without penalizing the Company relative to its average cost to obtain funds in the market. Requiring a refund with 7.45% interest will also more closely align the Company's interests with the public's interest that interim rates not repeatedly exceed final rates by large margins.[175]

The Commission issued its Order in the last case on September 3, 2013; the twelve and a half months that have passed since that time have not seen any material change that should affect the Commission's reasoning. The only thing that has changed is that Xcel has asked for even more money this time around. Limiting the interest rate on the interim rate refund to the prime rate would result in excessive returns for the Company and an unfair burden on ratepayers. To avoid this imbalance, the ALJ recommends that the Xcel provide interest on interim rates at its rate of return.

IV. CLASS COST OF SERVICE STUDY

93. The Commission acts in a legislative capacity when it is "allocating costs between utility customers and balancing various factors to achieve a fair and reasonable allocation of those costs."[176] One tool that the Commission has used to inform revenue apportionment is the class cost of service study ("CCOSS"), which estimates the amount that each customer class contributes to the utility's cost of providing service.[177] Conducting a CCOSS requires three general steps. First, a CCOSS functionalizes similar costs according to the Uniform System of Accounts, as designated by the Federal Energy Regulatory Commission ("FERC").[178] Second, the CCOSS classifies the functionalized costs as either customer, demand, or energy costs according to their purpose.[179] Finally, the functionalized and classified costs are allocated to various customer classes depending on how the costs were classified and caused.[180] Customer costs are the costs caused by a customer, regardless of whether the customer consumes electricity

[174] *Id.* at 39.
[175] *Id.*
[176] *City of Moorhead v. Minnesota Public Utilities Commission*, 343 N.W.2d 843, 846 (Minn. 1984).
[177] Ex. 375, at 2 (Nelson Direct).
[178] *Id.* at 3.
[179] *Id.*
[180] *Id.*

or not and are allocated based on the number of customer locations within each class.[181] Demand costs are the costs incurred by the company to meet the peak demand, and are allocated based on each customer class's contribution to peak demand.[182] Energy costs are caused by the amount of energy consumed and are allocated based on each class's energy consumption.[183] Since different customer classes are allocated different amounts of each cost, improperly classifying or allocating these costs can lead to false conclusions about a class's contribution to the utility's cost of providing service.

94. Xcel's CCOSS suggests that maintaining its existing revenue apportionment would result in the residential class paying approximately 97.8% of its cost of service and the C&I Non-Demand class paying approximately 99.5% of its cost of service.[184] Xcel then suggests a higher rate increase for these classes, purportedly to move their rates closer to the cost of providing service.

95. The Commission has previously recognized that cost of service studies "cannot establish precise values," because they "require considerable judgment and employ certain assumptions that might affect the results."[185] Moreover, the OAG has identified several ways that Xcel's improper methodology and subjective decision-making has resulted in inaccurate results in its CCOSS. Fixing these errors would result in a CCOSS that shows that, absent any need for an overall revenue increase, the residential and C&I Non-Demand classes currently each pay their cost of service, if not more.

A. MINIMUM SYSTEM STUDY.

96. Xcel's distribution system accounts for a substantial portion of the company's overall cost of providing service, consisting of more than $200 million of Xcel's requested revenue requirement.[186] FERC accounts 364 through 368 contain the costs of poles, transformers, services and other large portions of Xcel's distribution system.[187] The NARUC Electric Manual explains that these specific accounts contain both demand and customer costs, which must be properly classified to accurately determine the cost of providing service to the various customer classes.[188] Misclassifying these costs can have a significant impact on the CCOSS, since the residential class can pay more than 95% of the costs classified as customer costs, but less than 35% of the costs classified as demand costs.[189]

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[181] *Id.*; Ex. 408, at 20 (Ouanes Direct).
[182] *See* Ex. 375, at 3 (Nelson Direct); Ex. 408, at 20 (Ouanes Direct).
[183] *See* Ex. 375, at 3 (Nelson Direct); Ex. 408, at 20 (Ouanes Direct).
[184] Ex. 375, at 5 (Nelson Direct).
[185] Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-111/GR-09-175, at 12 (May 24, 2010).
[186] Ex. 375, at 14 (Nelson Direct).
[187] *Id.* at 13.
[188] *See Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, at 90 (Jan. 1992) (hereinafter NARUC Electric Manual).
[189] Ex. 375, at 14 (Nelson Direct).

97. Xcel's classification of FERC accounts 364 through 368 uses analytical methods that overestimate the customer costs of each account, a problem that Xcel compounds by selecting incorrect and outdated inputs that further increase the customer costs generated by its analysis.

1. The Customer Cost Portion of Xcel's Distribution System.

98. Since FERC accounts 364 through 368 contain both customer and demand costs, a minimum system study is conducted on the utility's distribution system to determine the proper classification of costs in each account.[190] The minimum system study seeks to determine the proportion of these FERC accounts that is paid simply to provide service to a customer, regardless of demand, and the proportion that is paid to meet a customer's demand.[191] The NARUC manual provides two methods of conducting a minimum system study: the minimum-size-of-facilities method ("minimum-size method") used by Xcel, and the minimum-intercept or "zero-intercept" method.[192] While each of these methods designs a hypothetical minimum distribution system, they are conceptually different from one another and, even if performed correctly, will likely lead to different results.[193]

99. The minimum-size method "assumes that a minimum size distribution system can be built to serve the *minimum loading requirements* of the customer."[194] Conducting a minimum-size analysis involves determining the smallest (or minimum-sized) distribution equipment installed by a utility and constructing a hypothetical distribution system entirely from this minimum-sized equipment.[195] The costs associated with this hypothetical minimum distribution system are classified as customer costs, while all costs of the utility's distribution system that exceed this hypothetical minimum system are classified as demand costs.[196]

100. The zero-intercept method "seeks to identify that portion of plant related to a hypothetical *no-load* or zero-intercept situation."[197] The zero-intercept method constructs a hypothetical no-load distribution system by incorporating a more technically demanding regression analysis.[198] Like the minimum-size method, the costs of the hypothetical distribution system developed from a zero-intercept analysis are classified as customer costs, and all costs of the utility's distribution system in excess of the hypothetical system are classified as demand costs.[199]

2. Over-classification of Customer Costs.

101. Xcel's minimum system study is based on the minimum-size method. This method requires considerably less data and a simpler analytical approach than the zero-intercept method.

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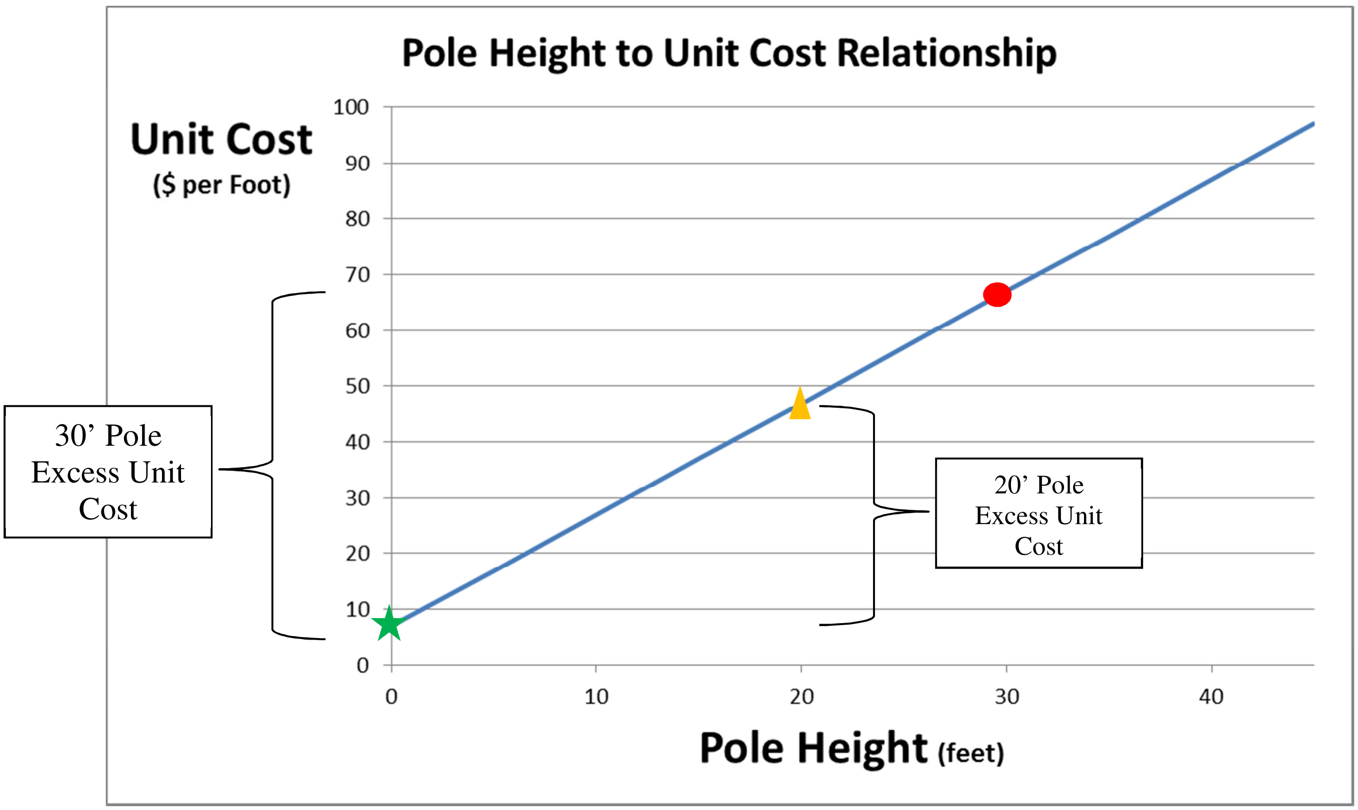
[190] Ex. 375, at 14 (Nelson Direct).
[191] *Id.*
[192] *See* NARUC Electric Manual, at 90.
[193] Ex. 375, at 16 (Nelson Direct).
[194] NARUC Electric Manual, at 90 (emphasis added).
[195] *Id.* at 90–91; Ex. 375, at 16 (Nelson Direct).
[196] NARUC Electric Manual, at 91.
[197] *Id.* at 92 (emphasis added).
[198] Ex. 375, at 16–17 (Nelson Direct).
[199] NARUC Electric Manual, at 92.

The NARUC manual recognizes, however, that it is generally less accurate than the zero-intercept method in identifying the customer costs and demand costs of a distribution system.[200] The NARUC manual also states that the minimum-size method used by Xcel "generally produces a larger customer component" than would be produced by the more precise zero-intercept method.[201] This is because the minimum-sized method incorrectly classifies some costs of providing load to customers—and, therefore, fulfilling their demand—as customer costs.[202] The graph below provides one example of how using the cost of either a 20-foot or 30-foot utility pole in a minimum-sized method overstates the customer cost portion of a utility's distribution system:



In this graph, the blue line is a regression line demonstrating the cost of utility poles as they get taller to serve more demand or material costs.[203] The location of where the line crosses the Y-axis, marked by the star, represents the zero-intercept value—the cost of installing a utility pole absent any customer demand.[204] In a zero-intercept analysis, all of the unit costs below the star would be classified as customer costs. Any unit costs incurred by the utility above the star would

[200] *See id.* at 92.
[201] *Id.* at 91, 92.
[202] Ex. 375, at 19 (Nelson Direct)
[203] Ex. 375, at 18 (Nelson Direct). As Mr. Nelson explains, this graph assumes a positive linear relationship between the unit cost and pole height, which is not necessary for the example to be valid but helps for understanding. Further, the graph assumes that the model is specified correctly. *Id.* at 18, n. 9.
[204] *Id.* at 20.

be classified as demand costs, since the specific heights of the poles installed by the utility would depend on customer demand.

102. While the star on the graph above represents the zero-intercept value, the triangle and circle represent the unit costs of installing a 20-foot or 30-foot pole, respectively.[205] Since the cost of installing utility poles theoretically increases as they get taller due to increasing material costs, the 20-foot pole costs more than the zero intercept, and the 30-foot pole costs more than the 20-foot pole. Therefore, conducting a minimum system study using either a 20-foot or 30-foot pole as the utility's "minimum-sized" pole will inevitably classify more of the utility's distribution system as customer costs than would a zero-intercept analysis. Specifically, the difference between the cost of either the circle or the triangle in the graph and the cost of the star represents the excessive customer costs of using a minimum-sized method. As OAG witness Mr. Nelson explains, this graph "demonstrates that in theory the minimum-size method, as opposed to a zero-intercept method, overestimates the proportion of customer costs by using too high of a unit cost to construct the minimum system."[206] This is not only true for utility poles, but is the case for all of the distribution components included in FERC accounts 364-368.

103. While the NARUC manual states that the difference between the minimum-size method and the more precise zero-intercept method "*may* be relatively small,"[207] this is not always the case, and the record demonstrates that the difference between the two methods is likely significant here. The exact difference between each method cannot be known in this case because Xcel claims to not have the necessary data to perform a zero-intercept analysis or necessary data for a properly conducted minimum-size method. Mr. Nelson explains, however, that since the materials used in Xcel's minimum-size method are incurred to serve a specific level of demand, removing the material costs from Xcel's minimum system study provides a proxy for estimating the results of a zero-intercept analysis. Removing the material costs from Xcel's minimum system study would result in a shift of approximately 33% of Xcel's customer costs to demand costs in its cables account.[208]

104. In addition, the OAG identified one instance in which Xcel's minimum-size analysis did not even use the smallest equipment installed in Xcel's distribution system. Specifically Mr. Nelson noted that while Xcel uses a cable size of "1/0 Alum" in its minimum system study, it uses a smaller and cheaper cable, "#2 Alum," within its distribution system.[209] Incorporating this smaller cable into Xcel's minimum-size analysis would result in a 6.5% shift of customer costs to demand costs in Xcel's cables account—a shift of $1.7 million away from the Residential class. In other words, this $1.7 million shift results from making a single change to a single FERC account within Xcel's minimum system study. Moreover, using a smaller #2 Alum cable in a minimum system study would still produce excessive customer costs, since the minimum system study would still rely on a minimum-size analysis rather than a zero-intercept analysis.

[205] *Id.* at 20.
[206] Ex. 375, at 20 (Nelson Direct).
[207] NARUC Electric Manual, at 92 (emphasis added).
[208] Tr. Evidentiary Hearing, Vol. 3, at 228–29 (Nelson) (Aug. 13, 2014); Ex. 381, REN-31, at 2 (Nelson Surrebuttal Schedules – Trade Secret) (indicating that the material costs of Xcel's cable accounts are one-third of the company's installed costs).
[209] Ex. 378, at 6 (Nelson Surrebuttal).

Incorporating the more precise zero-intercept analysis to remove all demand costs from the hypothetical minimum system would produce an even larger shift in Xcel's study.

105. During cross examination, Xcel attempted to deflect Mr. Nelson's critique that the company incorrectly used an excessively large and expensive cable in its minimum system study by claiming that, in another account, Xcel's minimum-size analysis used equipment that is smaller and presumably cheaper than any equipment it currently installs. Specifically, Xcel noted that while it uses a 30-foot utility pole in its minimum system analysis, the smallest pole it currently installs is 35 feet tall.[210] But Xcel's implicit claim that its use of an incorrect cable size is rectified by its use of an incorrect pole height in a different account is flawed.

106. Xcel has not identified the specific cost difference between the 30-foot poles used in its minimum system study and the 35-foot poles that it currently installs. Therefore, Xcel has not quantified the amount that would be classified as customer costs and demand costs if it had used the 35-foot pole that it currently installs. This failure is compounded by the fact that, unlike the simplified example identified above, utility poles do not differ solely on the basis of height. For example, Xcel indicated that it recently changed to a standard utility pole with a different diameter and, therefore, a different strength and size than previous poles it used.[211] But the diameter of the 30-foot pole used in Xcel's minimum system study was not explicitly considered in its minimum-size analysis.

107. Since the minimum system study analyzes a utility's embedded costs, using a pole that Xcel only recently began installing can lead to incorrect results. As Mr. Nelson points out, "Xcel could have just started installing 35-foot class 4 poles last year and have 100 of them installed, while there could be over 100,000 30-foot poles currently installed in the distribution system."[212] Therefore, the record does not support Xcel's implicit claim that the inaccuracy in it cables account is mitigated by the inaccuracy in its poles account. More importantly, fixing both of the errors in its analysis would not eliminate the over-classification of customer costs inherent in the minimum-size method used by Xcel. The body of evidence amply demonstrates that Xcel's minimum system study significantly overestimates the customer costs in its CCOSS to the detriment of residential and small business ratepayers.

3. Reliability of Xcel's Minimum System Study

108. Xcel has no standards for selecting the equipment used in its analysis. When asked how the company selected the equipment used in its minimum size method, Xcel responded that the equipment was "selected by [its] Distribution Engineering area according to its field experience and its evaluation of the smallest practical sized equipment inventories held in the Company's inventory."[213] This response provides no guidance on how Xcel's personnel selected the supposedly "smallest practical sized equipment" and lacks any criteria that would allow its analysis to be replicated and checked by the OAG, DOC, or other intervenors.

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[210] Tr. Evidentiary Hearing, Vol. 3 at 256–57 (Nelson) (Aug. 13, 2014).
[211] Ex. 379, REN-32 (Nelson Surrebuttal Schedules).
[212] Ex. 378, at 8 (Nelson Surrebuttal).
[213] Ex. 376, REN-5 (Nelson Direct Schedules).

109. According to Xcel, most, if not all, of its minimum-size analyses are premised on data last calculated in 1991, and the company does not currently track the data that would allow it or anyone else to update or replicate the calculation used in its current study.[214] Specifically, Xcel last estimated the average cost of its minimum-distribution equipment in 1991. Since then, Xcel has simply inflated this average cost calculation using the Handy Whitman Index ("HWI").[215] But the HWI should not be used to estimate costs that can be specifically determined from current data. Rather, as Mr. Nelson explains, the HWI should be used to approximate costs that cannot be otherwise determined, such as anticipated future costs.[216] By using the HWI to inflate old data for 23 years, instead of using the actual costs, Xcel's minimum system study produces rough estimates of cost causation at best. Accordingly, even without the substantial evidence that Xcel's study overestimates customer costs, the rough estimates produced from inflating 23-year-old data are not sufficient to conclude that one or more classes are not paying their cost of service.

110. To address the many inadequacies of Xcel's minimum system study, the ALJ recommends that Xcel provide a better representation of the customer costs and demand costs of its distribution system in future cases. First, Xcel should conduct the more precise zero-intercept analysis in future rate cases, and to provide parties with data sufficient to verify and reproduce its minimum system study. Second, the ALJ recommends that the minimum system analysis used in this case should be adjusted to classify and allocate 10% more capacity costs and 10% less customer costs than recommended by Xcel. Since the record indicates that removing material costs from Xcel's minimum system study would result in a 33% shift in one account, this limited change begins to correct for the errors produced by Xcel's use of the minimum-size method and by its failure to incorporate the minimum-size equipment throughout its analysis.

B. CLASSIFICATION OF NOBLES AND GRAND MEADOW WIND FACILITIES.

111. In its last three rate cases, Xcel classified the costs of company-owned wind generation the same way that it classifies the costs of its other generating facilities—by using the plant stratification or "Equivalent Peaker" method.[217] Plant stratification assumes that different types of generation contribute differently to Xcel's system and that the variety of generating units in the company's fleet are procured to minimize the overall cost of the system over time.[218] For instance, baseload and intermediate generating units built primarily for energy needs have higher capital costs and lower operating costs than peaking facilities built for capacity.[219] Therefore, the plant stratification method classifies the capital costs of a generating unit above those of an equivalent peaking facility as energy, since these higher capital costs were incurred to obtain the lower operating costs of energy production over time.[220] But since even baseload facilities

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[214] Ex. 377, at 2, 4 (Nelson Rebuttal).
[215] *Id.* at 2–3.
[216] Ex. 377, at 3 (Nelson Rebuttal).
[217] Ex. 408, at 22 (Ouanes Direct).
[218] Ex. 102, at 27 (Peppin Direct) (explaining that plant stratification recognizes that "[b]y selecting an optimal mix of these resources, we are able to minimize total system costs over time.")
[219] *Id.* at 12.
[220] *Id.* at 12–13.

contribute to a utility's capacity, the capital costs of generating facilities up to the cost of equivalent peaking plants are classified as capacity.[221]

112. Following this methodology, different generating resources in Xcel's system have varying proportions classified as capacity and energy—from 17% capacity and 83% energy for hydroelectric power to 100% capacity and 0% energy for strictly peaking facilities.[222] Using this method in previous cases to classify the costs of Xcel's company-owned wind facilities resulted in classifying approximately 5% of these facilities as capacity, and approximately 95% percent as energy.[223]

113. While using the plant stratification method in past rate cases for all of Xcel's wind facilities has produced results that align closely with cost causation principles, it has slightly over-classified the capacity portion of Xcel's Nobles and Grand Meadow facilities. Unlike traditional generation units, these facilities were not added to minimize the total costs of its system over time—an assumption of the plant stratification method. Rather, Xcel explains that these wind resources were added to comply with Minnesota's renewable energy standard ("RES"),[224] which requires Xcel to generate or procure at least eighteen percent of its energy from renewable technologies.[225] Therefore, since they were explicitly added to comply with the RES, Xcel's investment in the Nobles and Grand Meadow wind resources corresponds directly with the energy consumption of its customers, and was not impacted by the company's peak demand requirement.[226] Classifying Xcel's Nobles and Grand Meadow wind generation as energy recognizes the different purpose of these facilities and better aligns with cost-causation principles than continuing to use the same plant stratification method applied to other traditional generating resources.

114. Further, the specific attributes of wind generation also align better with classifying these resources as energy, rather than as capacity. For example, the NARUC manual suggests classifying capital costs incurred to reduce fuel costs as energy.[227] As Mr. Nelson explains, "[s]ince one of the major objectives of renewable energy is to reduce the amount of fossil fuel consumed, thus reducing fuel costs, the capital costs expended on wind projects fit this description."[228] Department witness Dr. Ouanes also explains that "wind facilities only generate electricity when the wind blows" and that, as an intermittent resource, "wind facilities cannot be dispatched and may not produce energy when needed as peaking plants do."[229] Therefore, while Dr. Ouanes prefers continuing to use plant stratification to classify approximately 95% of the

[221] *Id.* at 12.
[222] *Id.* at 13.
[223] Ex. 408, at 22. (Ouanes Direct).
[224] Ex. 102, at 27 (Peppin Direct).
[225] Minn. Stat. § 216B.1691, subd. 2a(b). The percentage of electricity Xcel must generate from renewable technologies will increase to 25% in 2016 and to 30% in 2020. *Id.*
[226] Ex. 375, at 8 (Nelson Direct).
[227] NARUC Electric Manual, at 21.
[228] Ex. 375, at 9 (Nelson Direct).
[229] Ex. 408, at 22–23 (Ouanes Direct).

cost of all of Xcel's wind generation as energy, he acknowledges that the OAG's recommendation to classify the Nobles and Grand Meadow facilities as energy is reasonable.[230]

115. While the OAG and Department each recommend methods that classify all or virtually all of the costs of these wind facilities as energy, Xcel recommends a dramatic and unsupported change from its past practice by classifying its Nobles and Grand Meadow facilities entirely as capacity. In addition to conflicting with cost-causation principles explained above, Xcel's recommendation is inconsistent with past Commission precedent and even the company's own arguments. These inconsistencies are extensively explained by Dr. Ouanes, who notes that the Commission agreed with Xcel's recommendation in its 2010 rate case to classify all of its wind facilities primarily as energy and concluded that "[w]ind resources by and large replace other energy resources, and contribute very little to capacity."[231] Dr. Ouanes also points out that Xcel argued in its 2008 rate case that the policy motivations of obtaining wind energy align with classifying it predominantly as energy:

> The purpose for accelerated development of wind energy is to obtain the environmental benefits of this particular source of <u>energy</u> (not capacity) as compare [sic] to other conventional <u>energy</u> (not capacity) sources. It is also well known that wind energy is intermittent and available only when the wind blows, which is further evidence that it is a source of intermittent <u>energy</u>, which may provide only a small capacity value. This is all reflected in the small 4.7% capacity value resulting for the Grand Meadow resource in the Company's stratification analysis.[232]

116. Finally, Dr. Ouanes cites company witness Mr. Peppin's own statement from Xcel's last rate case that Xcel believes that the plant stratification method appropriately classifies and allocates wind energy.[233] Xcel's abrupt change in this rate case is inconsistent with past Commission precedent and conflicts with cost causation principles and the purposes of obtaining wind resources. Therefore, the ALJ recommends that Xcel's Nobles and Grand Meadow wind facilities be classified as energy in the CCOSS.

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[230] Ex. 414, at 5 (Ouanes Surrebuttal); Tr. Evidentiary Hearing, Vol. 4, at 63 (Ouanes) (Aug. 14, 2014).
[231] Ex. 408, at 26 (Ouanes Direct) (*quoting* Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket. No. GR-10-961, at 21 (May 14, 2012)).
[232] Ex. 408, at 24-25 (Ouanes Direct) (*quoting* Rebuttal Testimony of Xcel witness Phillip J. Zins, *In the Matter of the Application of Northern States Power Company, a Minnesota corporation For Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket. No. GR-08-1065, Ex. 38, at 24).
[233] Ex. 408, at 25 (Ouanes Direct) (quoting the Direct Testimony of Xcel witness Michael A. Peppin, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. GR-12-961, Ex. 60, at 35,).

C. CLASSIFICATION OF OTHER PRODUCTION O&M EXPENSES.

117. Other Production O&M costs include non-fuel related expenses of plant operation and management, such as labor, non-fuel supplies, and maintenance.[234] The Commission has previously considered two methods to classify these costs: the location method[235] and the predominant nature method. The location method classifies Other Production O&M costs using the same classifications as the plant in which the costs were incurred.[236] For example, under the location method, the Other Production O&M costs incurred at a nuclear facility will be classified between energy and capacity functions according to the applicable classifications for a nuclear facility. The Commission has previously determined that the location method "best corresponds to the causes of [Other Production O&M] costs."[237]

118. In contrast, the predominant nature method classifies entire cost categories based on whether the cost category is considered "predominantly" capacity or energy-related.[238] For instance, since labor costs do not vary significantly based on the amount of energy produced, the predominant nature method considers them to be predominantly capacity related, and allocates labor costs entirely as capacity.[239] On the other hand, since material costs are considered variable, all material costs are classified as energy. The problem with the predominant nature method is that it fails to distinguish between the costs associated with operating different plants that contribute differently to a utility's system. The predominant nature method would, for example, classify all labor costs incurred at a nuclear facility as capacity costs. But since nuclear facilities contribute largely to energy production, classifying labor costs from these plants as capacity leads to warped and absurd results. This is particularly true since the cost of labor at nuclear facilities is typically higher than other plants due to added safety requirements.[240]

119. In Xcel's last three rate cases, the company recommended, and the Commission ordered, that Xcel's Other Production O&M costs be classified based on the location method. Classifying these costs based on the location method resulted in 75 percent weightage as energy and a 25 percent weightage as capacity in Xcel's last rate case.[241] But despite the Commission's decisions in the last three rate cases, Xcel now proposes to classify its Other Production O&M costs using the predominant nature method.[242] Using the predominant nature method in this case would result in a dramatic shift in the classification of these costs, with only 21.6 percent

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[234] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket. No. GR-10-971, at 17 (May 14, 2012).
[235] Xcel also refers to the location method as the "overall investment method." Ex. 102, at 24 (Peppin Direct).
[236] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket. No. GR-10-971, at 17 (May 14, 2012).
[237] *Id.* at 17.
[238] *See* Ex.102, at 22–23 (Peppin Direct).
[239] *See id.* at 23.
[240] *See* Ex. 408, at 35 (Ouanes Direct).
[241] Ex. 102, at 21 (Peppin Direct).
[242] *See id.* at 23.

weightage as energy and 78.4% as capacity—increasing the costs allocated to the Residential class in Xcel's CCOSS by $12.5 million.

120. Xcel has not provided any valid basis to change from the location method used in its last three rate cases to the predominant nature method. Rather, Xcel's witness Mr. Peppin states throughout his rebuttal testimony that the predominant nature method is suddenly more "refined" than the location method, and that the 1992 NARUC Electric Manual characterizes the location method as "not standard practice."[243] But Xcel has not explained how either the statements in the 1992 NARUC Electric Manual or the basic differences between the location and predominant nature methods were not appropriately considered in the Commission's decisions (and the company's recommendations) to use the location method in the company's last three rate cases.

121. Xcel also attempted to imply that the Commission signaled a preference for the predominant nature method in the company's last rate case by requiring it to file a CCOSS that classified specific, energy-related costs as energy in this case.[244] The Commission's order on this matter provides as follows:

> In the initial filing of its next case, Xcel shall refine its Class Cost of Service Study cost allocation method by identifying any and all Other Production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, *while allocating the remainder of Other Production O&M costs on the basis of the Production Plant*.[245]

Dr. Ouanes pointed out in his direct testimony that the Commission's language actually signals its continued preference for the location method. The ALJ agrees. The company has not provided any basis to reverse three rate case precedents in which the location method was used, and to make the dramatic shift to the less precise predominant nature method. Accordingly, the ALJ recommends that Other Production O&M costs be classified based on the location method in the CCOSS.

D. ALLOCATION OF LOST REVENUE FOR ECONOMIC DISCOUNTS.

122. Xcel provides discounts in order to attract and retain large energy customers.[246] These discounts are provided on an energy basis, meaning that the overall cost of providing these

[243] *See id.* at 26–27.
[244] *See* Ex. 102, at 22 (Peppin Direct); Ex. 408, at 34 (Ouanes Direct) (noting that "the Company's current support for a substantial change in classification and allocation of the Other O&M expenses through the use of the predominant nature methodology is only based on Xcel's perception that this 'methodology is more consistent with the desire expressed during the 2013 rate case that the Company take a more expansive view of energy-related Other Production O&M costs'")
[245] Findings of Fact, Conclusions and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket. No. GR-12-961, at 53, (Sept. 3, 2013) (emphasis added).
[246] Ex. 102, at 19 (Peppin Direct).

discounts vary with the amount of energy consumed.[247] Xcel recovers the lost revenues associated with these discounts, and proposes to allocate these lost revenues according to its present revenue allocator.[248] In proposing to use its present revenue allocator, Xcel did not consider cost causation principles. Rather, Xcel explicitly cites a policy goal for its chosen allocation: "[w]e therefore used the present revenue allocator because it reasonably balances the interests of all classes in a way that is consistent *with the overall goal of helping support economic development*."[249] But As Dr. Ouanes explains, since the economic discounts are provided on an energy basis, the lost revenues should be recovered on the same basis—using a straight kWH energy allocator.[250] Dr. Ouanes' proposal is both inherently fair and incorporates cost causation factors appropriate for performing a CCOSS.

123. During cross examination of Mr. Ouanes, the Xcel Large Industrial group ("XLI") supported Xcel's proposed allocation by indicating that the policy of maintaining Xcel's revenues provides the sole basis for allowing these economic discounts.[251] From this premise, XLI appeared to argue that Xcel's CCOSS should reflect this policy by using the company's revenue allocator to apportion revenues lost from its economic discounts. But even accepting the argument that economic discounts are incurred with a single policy goal of maintaining Xcel's revenues, the CCOSS should not incorporate embedded policy decisions into its cost analysis. Moreover, XLI's position fails to recognize that Xcel's revenues are a function of *both* the amount of energy sold and the rate paid for that energy. The costs associated with providing economic discounts, however, relate only to the amount of energy consumed. Accordingly, since the lost revenues associated with these discounts are caused by energy, they should be allocated as energy as recommended by Dr. Ouanes. Therefore, the ALJ recommends that the lost revenue associated with economic discounts be allocated as energy in the CCOSS.

E. XCEL'S D10S ALLOCATOR.

124. Xcel uses the D10S allocator to allocate millions of dollars of costs classified as demand within its CCOSS.[252] The D10S allocates costs using each class's contribution to the company's peak demand. Therefore, if Xcel has a higher peak, classes that contribute more to peak demand will be allocated a greater share of costs. Since residential customers' peak demand fluctuates more than other classes, a higher overall peak demand will lead to greater allocation to the residential class.

125. In determining the company's peak demand, the D10S uses a summer-only peak. While Xcel previously used a demand allocator that incorporated both a summer and winter peak, it supports using the summer-only peak in the D10S allocator by stating that the company must plan its reserve margin requirements based on the utility's coincident peak with MISO.[253]

[247] Ex. 408, at 38–39 (Ouanes Direct).
[248] Ex. 102, at 19 (Peppin Direct).
[249] *Id.* (emphasis added).
[250] Ex. 408, at 39 (Ouanes Direct).
[251] Tr. Evidentiary Hearing, Vol. 4, at 83–86 (Ouanes) (Aug. 14, 2014).
[252] Ex. 375, at 10 (Nelson Direct).
[253] *See* Ex. 375, at 11 (Nelson Direct).

Despite its argument in support of a summer-only peak, Xcel does not use MISO's coincident peak to calculate its D10S allocator. Rather, Xcel uses its own system peak.[254] By using its own system peak, rather than MISO's coincident peak, Xcel significantly overestimates the costs of serving those customer groups that contribute more to peak demand. Specifically, Mr. Nelson explained that NSP's system peak was higher than its coincident peak with MISO in four of the last five years.[255] These peaks differed by as much as 8%.[256]

126. Xcel witness Mr. Peppin acknowledged that calculating the D10S allocator based on MISO's coincident peak "would be consistent with MISO's resource adequacy rules and would reflect cost causation."[257] Mr. Peppin claims, however, that Xcel does not have the data necessary to conduct a D10S analysis.[258] Regardless of whether Mr. Peppin's claim is accurate, the record demonstrates that Xcel's use of a D10S allocator does not reflect cost causation and is allocating excessive costs to the residential class. As Mr. Nelson explains, MISO's coincident peak is typically earlier in the day than Xcel's, and "[d]uring MISO's peak . . . it is likely that fewer of [Xcel's] residents would be home from work compared to NSP's own peak. It is obvious that the proportion that residents would contribute to demand would be less if MISO's peak were used."[259] Accordingly, Xcel's use of its own system peak in the D10S allocator incorrectly allocates costs to the detriment of residential customers. The ALJ therefore recommends that Xcel be required to use MISO's coincident peak in calculating the D10S allocator in future cases. In this case, Xcel's use of its own system peak contributes to the inherent imprecision of the CCOSS and the over-estimation of the costs caused by the residential class.

V. REVENUE APPORTIONMENT AND RATE DESIGN

A. REVENUE APPORTIONMENT.

127. To varying degrees, Xcel and the Department each modified Xcel's revenue apportionment to increase the rates of residential and small business ratepayers more than other classes.[260] Both parties claim that their recommendations are based on a goal of moving all classes closer to cost, while moderating the overall increase to a class.[261] The testimony of OAG witnesses Mr. Nelson, however, demonstrated that Xcel's residential and Small General Service customers are currently paying their cost of service, if not more.[262] While a strict cost-based approach would result in possibly applying a *lower* rate increase for residential and small business customers, the OAG recommends that any rate increase authorized by the Commission

[254] *Id.* at 11.
[255] *Id.* at 12.
[256] *Id.* at 12.
[257] Ex. 102, at 37 (Peppin Direct).
[258] *Id.* at 38.
[259] Ex. 378, at 12–13 (Nelson Surrebuttal).
[260] Ex. 107, at 5 (Huso Rebuttal); Ex. 422, at 3–4 (Peirce Surrebuttal).
[261] Ex. 105, at 9–10 (Huso Direct); Ex. 420, at 9 (Pierce Direct)
[262] Ex. 378, at 17 (Nelson Surrebuttal).

use Xcel's existing revenue apportionment. The OAG's recommendation recognizes that the CCOSS is an imprecise tool that relies on many subjective decisions.[263]

128. The OAG's recommended revenue apportionment is also supported by the Commission's directive to incorporate non-cost factors when designing rates.[264] These non-cost factors include, among others, the customers' ability to pay, customer acceptance of rates, historical continuity of rates, and the ability of some customer classes to pass costs on to others.[265] Each of these non-cost factors provides further justification for limiting rate increases for the residential and small C&I classes. The residential class contains many ratepayers who have no ability to pay increased utility costs, such as low income families and seniors living on a fixed income. Even Xcel's CCOSS demonstrates that residents are paying nearly 98% of their cost of service and small businesses are paying more than 99%.[266] Increasing the apportionment for these classes, on this record, places far too much weight on an admittedly imprecise tool to the detriment of many ratepayers struggling to pay for a necessary service. For these reasons, The ALJ recommends that any revenue increase be collected using Xcel's existing revenue apportionment.

B. REVENUE DECOUPLING.

129. Xcel proposes to implement a Revenue Decoupling Mechanism ("RDM") for only its residential and small business customer classes.[267] In general, decoupling is a mechanism that allows a utility to true-up revenue deviations from a set amount.[268] Under decoupling, if a utility's revenues fall below the base amount, a utility may surcharge customers; if revenues climb above the base amount, the utility must refund customers. The two general types of revenue decoupling are full decoupling and partial decoupling, and there are various ways to design specific decoupling proposals.[269] Section 216B.2412 of Minnesota Statutes requires the Commission to establish standards and criteria for decoupling proposals that mitigate the impact on public utilities of state energy-savings goals "without adversely affecting utility ratepayers."[270] The statute further directs the Commission to authorize one or more pilot programs to assess the merits of decoupling.[271] While the Commission has approved three revenue decoupling mechanisms for gas utilities, it has not approved a decoupling mechanism for an electric utility.[272]

[263] Ex. 375, at 37–38 (Nelson Direct).
[264] Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. GR-09-175, at 14 (May 24, 2010).
[265] *Id.*
[266] Ex. 375, at 5 (Nelson Direct)
[267] Ex. 109, at 2 (Hansen Direct).
[268] Ex. 417, at 9 (Davis Direct).
[269] *Id.*
[270] Minn. Stat. § 216B.2412, subd. 2.
[271] Minn. Stat. § 216B.2412, subd. 3.
[272] Ex. 417, at 10 (Davis Direct).

130. Under its proposal, Xcel would calculate from the rate case the Commission-authorized revenue requirement on a per-customer basis.[273] Each year thereafter, Xcel would use the Commission-authorized per-customer revenue requirement to calculate its total allowed revenues.[274] Xcel would then compare its allowed revenues against its actual weather-normalized revenues for the year and either surcharge or refund customers over the next twelve months.[275] The RDM proposed by Xcel also includes a "soft" cap of five percent on surcharges. This "soft" cap means that any time the RDM produces a surcharge resulting in a rate increase above five percent, the surcharge would be limited to the five percent cap. The uncollected surcharge above the cap would be deferred to the following year and collected.

1. Quantifiable Benefits of the proposed RDM.

131. Xcel suggests that its RDM proposal is in the public interest because it removes the company's financial disincentive to promote conservation and energy efficiency.[276] But Xcel has indicated that it will not track or otherwise quantify how its decoupling program affects conservation or energy consumption.[277] Moreover, Xcel admits that it has previously been successful in promoting conservation programs without having a decoupling mechanism, and that "the [c]ompany has been experiencing reductions in residential and small commercial use per customer in recent years, a trend that is expected to continue according to the [c]ompany's forecast."[278] While Xcel suggested in direct testimony that it may not be willing to continue promoting programs that encourage conservation and energy efficiency without decoupling,[279] it later clarified that it intends to meet is statutorily-targeted conservation goals regardless of whether its RDM is approved.[280]

132. Xcel supports its proposed RDM by arguing that, despite its commitment to meet its conservation goals without decoupling, achieving future benchmarks will be more difficult due to "changing market circumstances." But, Xcel itself states that the only "market circumstance" that decoupling seeks to address is the company's supposed disincentive to promote conservation. Xcel's admission that residential and small business electric consumption use will continue to decline and that the company will continue to pursue its conservation goals rebut its claim that that it needs decoupling to continue promoting greater conservation efforts. For these reasons, Xcel has not explained or quantified any meaningful benefits of its RDM.

2. Negatively Impacts of an RDM.

133. The record establishes that Xcel's RDM proposal would likely have a significant negative impact on ratepayers. First, the record evidence strongly suggests that the RDM would lead to

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[273] *Id.* at 8.
[274] *Id.*. Therefore, Xcel's allowed revenues would vary based on the number of customers added or subtracted in a given year.
[275] *Id.*
[276] Ex. 109, at 2 (Hansen Direct).
[277] Xcel Response to OAG IR 1002, Ex. 376, REN-16, at 1–2 (Nelson Direct Schedules).
[278] Ex. 109, at 6–8 (Hansen Direct).
[279] Ex. 109, at 8 (Hansen Direct).
[280] Tr. Evid. Hearing, Vol. 3, at 94-95 (Hansen) (Aug. 13, 2014).

substantially higher utility rates for the affected customers. If decoupling had been implemented over the past five years, ratepayers would have paid net surcharges of between $15.6 million for a full decoupling program and $70.4 million for a partial decoupling program.[281] As Mr. Nelson explains, the substantially larger negative impact of partial decoupling may be related to weather trends and the increasingly warmer summers that increase Xcel's sales.[282]

134. Xcel's RDM proposal incorporates the partial decoupling model that would have resulted in the significantly larger net surcharge. Xcel apparently decided upon a partial decoupling model, rather than a full decoupling model, before it consulted its witness on the subject, Mr. Hansen.[283] Therefore, Xcel did not choose to offer a partial decoupling model based on Mr. Hansen's analysis and comparison of the benefits and detriments of partial and full decoupling. Rather, Xcel directed Mr. Hansen to propose the specific model that would have had the larger revenue impact over the past five years.

135. Xcel's proposed five percent "soft" cap does not mitigate the adverse rate impacts of its decoupling proposal. As Department witness Mr. Davis explains: "Xcel's proposed 'soft cap' is really not a cap since it would not change the size of a surcharge, just the timing of it . . . ."[284] Further, even if Xcel implemented a "hard" cap of five percent, ratepayers could have been subjected to *annual* surcharges of up to $38.8 million and $46.7 million during the past five years.[285] Reducing the hypothetical "hard" cap to 2.5% would still have allowed Xcel to surcharge customers more than $50 million during this time.[286]

136. Xcel's RDM could also add significantly to customers' confusion over their already complicated utility bills. The RDM adds surcharges or refunds to customer bills, accounting for amounts deferred from previous years. Moreover, due to Xcel's proposed soft cap, surcharges applied to true up for "under-recovery" in one year could be applied to customers' bills for multiple years going forward. For example, under Xcel's proposed RDM, customers in 2017 could be paying surcharges to account for under-collections in 2015. Moreover, those same customers could be simultaneously receiving refunds for over-collections in 2016. Expecting customers to understand and accept these complicated processes is unrealistic.

137. For these reasons, the ALJ recommends that the RDM be rejected. If a decoupling program is approved, however, the ALJ recommends that the Commission order several modifications suggested to ensure that the program has minimal negative impacts on ratepayers and achieves its intended purpose. Specifically, any RDM enacted should be a three-year pilot, full decoupling mechanism with a hard cap of one percent. Further, to ensure that the RDM is achieving its stated goals of supporting conservation efforts, Xcel should be prohibited from

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[281] Ex. 417, at 28 (Davis Direct). Mr. Davis notes that his full decoupling analysis is "dominated by a large surcharge of $25.2 million in 2009" and that, if 2009 was not included in his analysis, full decoupling would have resulted in net refunds to customers. *Id.* at 29.
[282] Ex. 375, at 56 (Nelson Direct).
[283] Tr. Evid. Hearing, Vol. 3, at 101 (Hansen) (Aug. 13, 2014).
[284] Ex. 417, at 33 (Davis Direct).
[285] *Id.*
[286] *Id.*

surcharging customers in the year after it fails to achieve energy savings goals of 1.2 percent of retail sales.[287]

C. Inclining Block Rates.

138. A proposal to implement an inclining block rate ("IBR") structure was introduced for the first time in this rate case in the direct testimony of Clean Energy Intervenors ("CEI") witness Paul Chernick.[288] Mr. Chernick's IBR proposal includes four consumption blocks for summer and four different consumption blocks for winter, each with specific inclining rates.[289] Following rebuttal and surrebuttal testimony from the OAG-AUD,[290] the Department,[291] and others, four parties—Xcel, the Suburban Rate Authority, the CEI, and the Energy Cents Coalition ("ECC")—executed a Stipulation on Inclining Block Rates ("Stipulation") outlining a specific process to further discuss implementing an IBR structure.[292] The Stipulation was not executed by the OAG-AUD, the Department, or several other parties in the rate case.

139. The Stipulation requires Xcel to file a proposal for an IBR rate structure 120 days after the Commission issues its final order in this case.[293] Xcel's proposal must include an IBR design "consistent with the 4-block design sponsored by CEI witness Paul Chernick . . ." and Xcel may also include "one alternative IBR structure," but must explain how its proposal is superior to Mr. Chernick's.[294] Thereafter, the Stipulation purports to require the Department to convene a stakeholder group to discuss concerns "raised by the parties to this proceeding."[295] The Department is then supposed to complete the stakeholder meetings discussing these concerns, and issue a full report to the Commission within 90 days of Xcel's filing.[296]

140. The record in this case demonstrates that an IBR structure could have severe, negative consequences for certain ratepayers and that implementing an IBR structure should be carefully and thoroughly considered. Moreover, assuming that IBR is effective at reducing consumption, implementing such a structure could impact the CCOSS, since the demand attributed to the residential class would presumably decline. Despite these concerns, the Stipulation outlines a process that unreasonably restricts any future discussion of potential implementing an IBR structure. Specifically, the process outlined in the Stipulation limits the number of IBR proposals that may be considered, the entities who may make specific IBR proposals, and, most

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[287] *See* Ex. 377, at 38–39 (Nelson Rebuttal).
[288] *See* Ex. 280 (Chernick Direct Public); Ex. 281 (Chernick Direct Trade Secret). Mr. Chernick's IBR structure was also supported in direct testimony of ECC witness Roger Colton. *See* Ex. 234.
[289] Ex. 280, at 18–19 (Chernick Direct). Mr. Chernick based his specific rates on Xcel's current regular residential energy charge.
[290] *See* Ex. 377 (Nelson Rebuttal); Ex. 378 (Nelson Surrebuttal).
[291] *See* Ex. 416 (Grant Rebuttal).
[292] *See* Ex. 135 (Stipulation on Inverted Block Rates).
[293] *Id.* ¶ 2.
[294] *Id.* ¶ 3.
[295] *Id.* ¶ 4.
[296] *Id.* ¶ 5.

importantly, the time-frame in which interested parties may discuss and attempt to address any negative impacts of IBR on specific customers.

1. Potential Harm to Ratepayers.

141. Recent history suggests that an improperly implemented IBR structure could substantially harm some ratepayers, particularly those with limited ability to alter their energy consumption. In CenterPoint's 2008 rate case, the company executed a similar stipulated agreement with the ECC and Environmental Intervenors proposing a pilot decoupling program that included an IBR structure.[297] Just like in this case, the stipulating parties argued that the IBR structure would lessen the financial burden on low-use customers while increasing the conservation signal to high-use customers.[298]

142. The Department opposed the IBR structure in the CenterPoint case, noting that it would have detrimental impacts on some low-income, high-use customers, and specifically rebutted the ECC's contention that the number of low-income customers who would experience substantial bill increases was minimal.[299] Despite these concerns, the Commission accepted the stipulation in the CenterPoint case and ordered the IBR structure as part of a decoupling pilot program.[300]

143. The IBR structure ordered in the CenterPoint case substantially harmed certain ratepayers. In response to the company's first compliance filing, the OAG-AUD submitted numerous affidavits identifying ratepayers harmed by the structure, including senior citizens who spent large portions of their days at home, people who consumed more energy due to medical conditions, and some low-income customers.[301] These problems were further compounded by an extended billing cycle in which some customers were billed for 33 days or more in some months, thereby artificially pushing their consumption into higher tiers of the IBR structure.[302] To address these concerns, the Commission suspended the IBR structure the year after it was implemented and ordered a workgroup to study many unintended and detrimental consequences of the program.[303]

144. Despite extensive discussions, the workgroup was ultimately unable to resolve the many problems associated with CenterPoint's IBR. The workgroup could not develop adequate solutions for customer groups unfairly impacted by the IBR structure and concluded that, even if it could, the only way to identify members of these groups was through self-reporting.[304]

[297] *See* Findings of Fact, Conclusions of Law, and Order, *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket. GR-08-1075 (Jan. 11, 2010).
[298] *Id.* at 8.
[299] *Id.* at 9-10.
[300] *Id.* at 13.
[301] *See* Ex. 375, at 26–28 (Nelson Direct).
[302] *Id.* at 28.
[303] *See* Order Suspending Inverted Block Rate Structure, Authorizing Workgroup, and Requiring Revised Decoupling Rate Adjustment, *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket. No. GR-08-1075 (Oct. 4, 2011).
[304] *See* Ex. 375, at 29–30, 32 (Nelson Direct).

Relying on self-reporting created two, opposing problems. On the one hand, many people harmed by the IBR structure may not report themselves as members of an "at-risk" group. On the other hand, if too many high-use customers identified themselves as members of at-risk groups, the benefits and objectives of the IBR structure could be compromised.[305] The workgroup also uncovered new problems that it could not resolve, such as how to address situations in which multiple units were served by a single meter.[306] Due to the many significant, unintended consequences that the workgroup was unable to resolve, the Commission ultimately terminated the IBR program.

2. Evaluation of a Potential IBR.

145. The Stipulation restricts discussions of an IBR structure in virtually every meaningful way. These restrictions include: (1) limiting the number of IBR structures that may be considered to Mr. Chernick's proposal and one other proposal from the company; (2) limiting discussions of the IBR proposal to a time period that allows the Department to draft and submit a report within 90 days of Xcel's filing; and (3) limiting any concerns regarding IBR that may be discussed to those that were "raised by the parties in this proceeding." These restrictions are particularly unreasonable given the Commission's past experience with the CenterPoint IBR experiment, the fact that the IBR proposal in this case first arose in intervenor direct testimony, and the fact that the Commission is also considering a multi-year rate case and decoupling proposal. Accordingly, the ALJ recommends that the Commission reject the Stipulation. If, however, the Commission elects to pursue the possibility of adopting an IBR structure, the ALJ recommends that it open a general docket in which all interested parties may participate in thorough and extensive discussions on a variety of possible IBR structures, the problems that IBR may create, and potential solutions to these problems.

D. RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMER CHARGES.

146. The customer charge is a fixed, monthly charge designed to help recover the customer-related costs of providing service.[307] Xcel's current customer charge for residential and small business ratepayers varies from a low of $8 per month for residential standard overhead service to a high of $12 per month for residential underground electric heating.[308] Xcel has requested increasing these charges by $1.25 per month for all residential customers, and by $1.50 per month for its Small General Service class.[309]

147. Xcel's proposed customer charge is premised on a flawed CCOSS that, as described above, dramatically over-estimates the customer-related costs of its distribution system. Based on its flawed CCOSS, Xcel's proposed customer-charge would recover approximately 63% of

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[305] *See* Ex. 375, at 32–33 (Nelson Direct).
[306] *See* Ex. 375, at 30–31 (Nelson Direct).
[307] Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket. No. GR-12-961, at 31 (Sept. 3, 2013).
[308] *See* Ex. 375, at 40 (Nelson Direct)
[309] *See* Ex. 375, at 40 (Nelson Direct)

the customer-related costs of the residential class and 68% of the customer-related costs for Small General Service class.[310] But when the appropriate adjustments are made to its CCOSS, Xcel's existing customer charge already recovers these proportions of its customer-related costs. Specifically, when the OAG's improvements to Xcel's CCOSS are considered, Xcel's existing customer charge already recovers 63% of its customer costs from residents and 66% of its customer costs from the Small General Service class. Accordingly, Xcel's existing customer charge already recovers the proportion of its customer costs that Xcel seeks in this case.

148. CEI witness Mr. Chernick also explained that significant portions of the costs classified as customer costs in the CCOSS should not be recovered through the customer charge since they do not vary based on the number of customers on Xcel's system. Specifically, Mr. Chernick notes that Xcel's CCOSS classifies as customer costs the costs of providing coverage throughout its service territory, referred to as "area-spanning" costs.[311] As Mr. Chernick explains, area-spanning costs do not vary based on the number of customers in Xcel's service territory, but are classified as customer costs in the CCOSS largely because no better classification exists.[312] Accordingly, while classifying area-spanning costs as customer costs may arguably lead to a reasonable apportionment of costs among the classes, they are not an appropriate input in determining the appropriate customer charge. Excluding the area-spanning costs from Xcel's customer-cost calculation would result in residential customer costs of $6.51 and Small General Service costs of $8.51—a level considerably lower than Xcel's current customer charge.[313] Moreover, the customer-related costs of serving the residential class would be even lower if other costs that do not vary based on the number of customers were removed, such as the costs of transformers and service drops.[314]

149. Xcel's customers have also endured a rapid series of increases to the customer charge and already pay a level commensurate with other electric utilities in Minnesota. Xcel's monthly residential customer charge has been increased four times since January of 2010 to its current level of between $8 and $12 per month, depending on the specific customer group.[315] Xcel's proposed fifth increase raises the customer charge by another double-digit percentage for every customer group; from a low of 10.4% for residential underground electric heating to more than 15% for residential standard overhead customers.[316] Xcel proposes these dramatic increase despite the fact that its existing customer charge is already consistent with the other three electric investor-owned utilities in Minnesota, who each charge a monthly residential customer charge of either $8 or $8.50.[317] Based on the record evidence that Xcel's customer charge is already recovering a considerable portion of its customer-related costs, if not more, adding yet another

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[310] *See id.* at 43.
[311] *See* Ex. 280, at 28 (Chernick Direct).
[312] Ex. 293, at 6 (Chernick Rebuttal).
[313] *Id.* at 7.
[314] *Id.* at 7–8.
[315] *See* Ex. 375, at 41 (Nelson Direct).
[316] *Id.* at 40.
[317] Ex. 420, at 13 (Pierce Direct).

increase is unnecessary and excessive. Accordingly, the ALJ recommends that Xcel's customer charge remain constant.

RECOMMENDATIONS

The ALJ recommends that the Commission issue an Order providing that:

1. Xcel is entitled to gross annual revenues in accordance with the terms of the Report.

2. Within ten days of the service date of this Report, Xcel shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirements and the rate design decisions based on the recommendations made herein.

3. Xcel shall make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: October 14, 2014

Respectfully submitted,

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