

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange
Dan Lipschultz
Matthew Schuerger
Katie J. Sieben
John A. Tuma

Chair
Commissioner
Commissioner
Commissioner
Commissioner

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

ISSUE DATE: June 12, 2017

DOCKET NO. E-002/GR-15-826

FINDINGS OF FACT, CONCLUSIONS,
AND ORDER

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PROCEDURAL HISTORY

I. Initial Filings and Orders

On November 2, 2015, Northern States Power Company d/b/a Xcel Energy (Xcel, or the Company) filed this general rate case seeking three consecutive annual rate increases under the Multiyear Rate Plan statute.¹ The proposed rate increases would total \$297,100,000, or 9.8% over current rates, and would be phased in as follows:

1. a 2016 increase of \$194,600,000, or 6.4% over current rates;
2. a 2017 increase of \$52,100,000, an additional 1.7% over current rates; and
3. a 2018 increase of \$50,400,000, an additional 1.7% over current rates.

The filing included a proposed interim-rate schedule. On the same date, the Company filed a petition to establish a new base cost of energy for the period during which interim rates would be in effect; that petition was granted by order dated December 22, 2015.²

Also on December 22, 2015, the Commission issued three orders in this case:

- an order finding the rate-case filing substantially complete and suspending the proposed final rates;
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested-case proceedings; and

¹ Minn. Stat. § 216B.16, subd. 19.

² *In the Matter of the Application of Northern States Power Company for Approval of a New Base Cost of Energy*, Docket No. E-002/15-827, Order Setting New Base Cost of Energy (December 22, 2015).

- an order setting interim rates for the period during which the rate case was being resolved.

II. The Parties and Their Representatives

The following parties appeared in this case:³

- Northern States Power Company, represented by Eric F. Swanson, David M. Aafedt, and Joseph M. Windler, Winthrop and Weinstine, P.A.; Elizabeth M. Brama, Briggs and Morgan, P.A.; and Amanda Rome and Ryan J. Long, Assistant General Counsels with Xcel Energy Services, Inc.
- Minnesota Department of Commerce, Division of Energy Resources (the Department), represented by Julia E. Anderson, Linda S. Jensen, and Peter Madsen, Assistant Attorneys General.
- Office of the Minnesota Attorney General–Residential Utilities and Antitrust Division (OAG), represented by Ryan Barlow, Ian Dobson, Joseph Meyer, and Joseph Dammel, Assistant Attorneys General.
- Minnesota Chamber of Commerce (the Chamber), represented by Richard J. Savelkoul, Martin & Squires, P.A.
- Fresh Energy, Sierra Club, Wind on the Wires, Minnesota Center for Environmental Advocacy (MCEA), and Natural Resources Defense Council, (NRDC) (together, the Clean Energy Organizations) represented by Hudson Kingston, attorney with the MCEA, and Samantha Williams, attorney with the NRDC.
- An ad hoc association of large commercial customers, including JC Penney Corporation, Inc., Macy’s, Inc., Sam’s West, Inc. and Wal-Mart Stores, Inc. (together, the Commercial Group), represented by Alan R. Jenkins, Jenkins at Law, LLC.
- Suburban Rate Authority, represented by James M. Strommen and Adam C. Wattenbarger, Kennedy & Graven, Chartered.
- City of Minneapolis, represented by Corey Conover, Minneapolis Assistant City Attorney.
- CHS Inc.; Flint Hills Resources, LP; Gerdau Ameristeel US Inc.; USG Interiors, Inc.; and Unimin Corporation (together, Xcel Large Industrials, or XLI), represented by Andrew P. Moratzka, Sarah Johnson Phillips, and Emma J. Fazio, Stoel Rives, L.L.P.
- U.S. Energy Services and an ad hoc group of industrial, commercial, and institutional customers (together, ICI Group), represented by Peder A. Larson and Inga K. Schuchard, Larkin, Hoffman, Daly & Lindgren, Ltd.
- Energy CENTS Coalition (ECC), represented by Pam Marshall, Executive Director.
- AARP, represented by John Coffman, Attorney at Law.

³ The ALJ granted (with limitations) the Energy Freedom Coalition of America’s petition to intervene in the case, but the organization later withdrew.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Jeffery Oxley to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held an evidentiary hearing in Saint Paul October 25 – 27, 2016. After the hearings the parties filed initial briefs, reply briefs, and proposed findings of fact and conclusions of law.

The ALJ also held eight public hearings in the case, on the dates and at the locations set forth below:

- July 12, 2016 – Merriam Park Public Library, St. Paul – 1:00 p.m.
- July 12, 2016 – Earle Brown Heritage Center, Minneapolis – 7:00 p.m.
- July 13, 2016 – Intergovernmental Center, Mankato – 7:00 p.m.
- July 19, 2016 – Wilder Complex, Minneapolis – 1:00 p.m.
- July 19, 2016 – Woodbury Central Park, Woodbury – 7:00 p.m.
- July 20, 2016 – City Hall, Eden Prairie – 7:00 p.m.
- July 26, 2016 – Lake George Municipal Complex, St. Cloud – 7:00 p.m.
- July 27, 2016 – Southeast Technical College, Red Wing – 7:00 p.m.

In May 2016, the Chief ALJ appointed a mediator, ALJ Jeanne M. Cochran, at the request of Xcel. The mediator conducted a mediation over three days in July 2016. The mediation resulted in a partial settlement among most, but not all, parties.

In August 2016, the Company filed a Stipulation of Settlement (the Settlement) entered into by nine of twelve parties to this case (the Settling Parties). The Settling Parties stated that they were able to resolve, between them: (1) all revenue requirements issues, (2) issues related to a medical needs customer bill-payment-assistance program, and (3) issues related to street lighting.

The Settlement was not joined by the OAG, AARP, or the Clean Energy Organizations, and it was opposed in part by the OAG and AARP. The ALJ recommended that the Commission adopt the settlement.

IV. Public Comments

The Administrative Law Judge held eight public hearings, where the Company, the Department, the OAG, and the Commission's staff were available to make presentations and field questions from members of the public.

All public comments are filed in the case record. Written comments are labeled "Public Comment," of which the Commission and the ALJ received over 487. In addition, over 40 individuals provided oral comments at the public hearings. Comments generally, though not universally, opposed Xcel's request for a rate increase. Other concerns raised in public comments included matters of conservation and renewable or sustainable energy, nuclear power generation,

distributed generation, pollution from an Xcel-operated trash incinerator in Red Wing, employee (including executive) compensation, fuel costs, and service quality.

A more comprehensive summary of public comments considered by the ALJ and the Commission can be found in Attachment A to the Administrative Law Judge's Findings of Fact, Conclusions of Law, and Recommendations.

V. Proceedings Before the Commission

On March 1, 2017, the Administrative Law Judge filed his Findings of Fact, Conclusions of Law, and Recommendations (the ALJ's Report). The following parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, XLI, the Chamber, the Commercial Group, and the Clean Energy Organizations.

On May 4 and 11, 2017, the Commission heard oral argument from and asked questions of the parties. On May 11, 2017, the record closed under Minn. Stat. § 14.61, subd. 2.

Having examined the entire record in this case, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.⁴ The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers," citing Minn. Stat. § 216B.16, subd. 6.⁵ That statute is set forth in pertinent part below:

The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate recoverability, leaving to the Commission the tasks of determining (a) the accuracy and validity

⁴ Minn. Stat. § 216B.16, subds. 4, 5, and 6.

⁵ *In re Interstate Power Co.*, 574 N.W.2d 408, 411 (Minn. 1998).

of claimed costs; (b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs with the public interest.

In ratemaking, therefore, the Commission must decide a wide range of issues, from the accuracy of the financial information provided by the utility, to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking the Commission acts in both quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained,

[I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.⁶

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.⁷ Any doubt as to reasonableness is to be resolved in favor of the consumer.⁸

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the “just and reasonable” standard set by statute. As the Court of Appeals explained, quoting the Supreme Court,

⁶ *In re N. States Power Co.*, 416 N.W.2d 719, 722–23 (Minn. 1987) (citation omitted).

⁷ Minn. Stat. § 216B.16, subd. 4.

⁸ Minn. Stat. § 216B.03.

A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). “Preponderance of the evidence” is defined for ratemaking proceedings as “whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together 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.”⁹

D. Multiyear Rate Plan Statute

Minn. Stat. § 216B.16, subd. 19, authorizes the Commission to approve multiyear rate plans. A multiyear rate plan establishes the rates a utility may charge for each year of a specified period of years (not to exceed five years), based only on the utility’s reasonable and prudent costs of service over the term of the plan. The statute does not alter the ordinary requirement that the Commission find that the plan results in just and reasonable rates, or that the burden of proof is on the utility proposing the plan.

The statute also authorizes the Commission to establish the terms, conditions, and procedures for such plans, which it did by order on June 17, 2013.¹⁰ The Commission established that utilities may propose a multiyear rate plan to improve the regulatory process for recovery of (a) costs related to specific, clearly identified capital projects, and (b) appropriate non-capital costs.¹¹

II. Summary of the Issues

Many initially contested issues were resolved among several of the parties in the course of evidentiary proceedings. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; he recommended accepting them.¹²

Other issues remained contested, and some issues resolved among the settling parties were disputed by one or more non-settling parties. The following issues either were contested or otherwise require discussion.

Financial and Cost-of-Capital Issues

- ***Stipulation of Settlement***—Should the Commission approve the partial settlement, and if so, should the settlement be modified to address issues resolved by the settlement but disputed by nonsettling parties, including performance metrics, nuclear refueling outage

⁹ *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted).

¹⁰ *In the Matter of the Minnesota Office of the Attorney General—Antitrust and Utilities 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, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans (June 17, 2013) (the Multiyear Rate Plan Order).

¹¹ Multiyear Rate Plan Order at 12.

¹² ALJ’s Report ¶ 685.

accounting, interest on the interim rate refund, and the accuracy of Xcel's capital spending budgets?

Class-Cost-of-Service-Study (CCOSS) Issues

- ***Classification of Fixed Plant***—Should Xcel classify generation plant as demand-related and allocate those costs to each customer class based on the class's share of peak demand?
- ***Classification of D10S Allocator***—Should Xcel calculate its D10S Allocator based on its own system peak, MISO's peak, or by some other method?
- ***Usage of Peak Demand and Energy Losses***—Should Xcel be required to account for energy losses as part of its CCOSS?
- ***Calculation of Renewable Development Fund Rider Cost Allocation***—Should Xcel be required to allocate Renewable Development Fund Rider costs as 50% energy and 50% demand?

Rate-Design Issues

- ***Interclass Revenue Apportionment***—What is a fair and reasonable apportionment of responsibility for Xcel's revenue requirement among its customer classes?
- ***Fixed Customer Charges***—Should the Commission approve the Company's proposed increases in the fixed customer charges?
- ***Energy Charge Credit***—Should Xcel's energy charge credit be increased as proposed by the Chamber?
- ***Interruptible Service Discounts***—Should the Commission approve Xcel's proposed increases in its interruptible service discounts?
- ***Coincident Peak Billing***—Is any change to Xcel's Coincident Peak Billing practices warranted, as proposed by the Chamber?

These issues are examined individually below, with issues on which the Commission declines to accept the ALJ's recommendation discussed in greater detail.

III. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held three days of formal evidentiary hearings and eight public hearings. He reviewed the testimony of expert witnesses offered by 11 parties, and related hearing exhibits. He reviewed written comments submitted by over 400 members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law.

Based on this record, the ALJ made some 1,065 findings of fact and conclusions of law and made recommendations on stipulated, settled, and contested issues based on those findings and conclusions. The ALJ recommended that the Commission approve the Settlement, but in the

alternative made several recommendations on Settlement-related issues if the Commission determined not to approve the settlement.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below.

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations to the extent they are consistent with the decisions made herein.

FINANCIAL AND COST OF CAPITAL ISSUES

I. August 16, 2016 Stipulation of Settlement

A. Introduction

On August 16, 2016, Xcel filed a Stipulation of Settlement together with the Department, XLI, MCC, the Commercial Group, the SRA, Minneapolis, the ICI Group, and ECC (the Settling Parties).¹³ The OAG, AARP, the CEOs, and the EFCA did not join in the Settlement. The OAG and AARP opposed aspects of the Settlement, while the CEOs and the EFCA took no position on it.

The Settlement resolves all revenue-requirement issues between the Settling Parties, as well as issues related to a medical-needs-customer bill-payment assistance program and LED street lighting. Beyond the assistance program and street lighting, the Settlement does not address class cost of service or rate design. Rather, the Settling Parties agreed that class cost of service and rate design would be resolved through the contested-case process already underway.

The Settlement is expressly conditioned on its acceptance by the Commission in its entirety; if the Commission modifies it in a manner that creates a "material adverse impact" to any Settling Party, that party may withdraw from the Settlement under the process outlined in the agreement. Under that process, the withdrawing party would file a motion to refer the rate case back to the Administrative Law Judge for further contested-case proceedings. The Settling Parties would then be free to argue their original positions on issues resolved by the Settlement.

B. Elements of the Settlement

1. Rate Increases

The Settlement, in essence, would result in a four-year multiyear rate plan spanning calendar years 2016 through 2019.

The Settling Parties agreed to specified increases in Xcel's electric rates each year, with the exception of 2018, when there will be no rate increase. In return, Xcel agreed not to file a general

¹³ Minneapolis participated in the Settlement solely to support the resolution of street-lighting issues and took no position on the other issues addressed in the Settlement.

rate case for electric service prior to November 1, 2019, and to forego the use of riders, and limiting rider use to those already existing and specifically identified in a table attached to the Settlement.¹⁴

The Settling Parties agreed to a total rate increase of \$184.97 million, or approximately six percent, over four years. The yearly rate increases—incremental and cumulative—are shown in the following tables:

	Incremental Increase			
	2016	2017	2018	2019
Rate increase in millions	\$74.99	\$59.86	–	\$50.12
Percent increase	2.47%	1.97%	0.0%	1.65%

	Cumulative Increase			
	2016	2017	2018	2019
Rate increase in millions	\$74.99	\$134.85	\$134.85	\$184.97
Percent increase over current rates	2.47%	4.44%	4.44%	6.10%

2. 2016 Sales-Forecast True-up and Decoupling

a. 2016 Sales-Forecast True-up

In a rate case, the Commission ordinarily relies on a forecast of the utility’s sales to both (1) determine the utility’s test-year revenues at current rates and (2) set final rates sufficient to recover the test-year revenue requirement. In this case, however, the Settling Parties agreed that final rates should be set based on Xcel’s actual, weather-normalized 2016 sales.¹⁵

On March 16, 2017, Xcel filed its actual, weather-normalized sales for 2016. Softer-than-expected sales meant that the Company sold approximately one million fewer megawatt-hours in 2016 than had been forecast at the outset of the case. Truing up the revenue shortfall added \$59.99 million to the rate increase for 2016.

No party objected to the Settlement on the basis of the 2016 sales-forecast true-up, and, at hearing before the Commission, the Department and several other Settling Parties affirmatively indicated that the increase was acceptable.

¹⁴ August 16, 2016 Stipulation of Settlement, Attachment 3.

¹⁵ Weather-normalized sales data are adjusted to remove the effects of extreme weather.

b. Decoupling

In general, if a utility's actual sales differ from forecasted sales, it over- or under-recovers its revenue requirement. However, a revenue-decoupling mechanism can be used to sever the link between sales and revenues, ensuring that the utility will recover the revenue requirement established in a rate case, even if the sales forecast over- or underestimates actual sales.

Under "full decoupling," a utility compares the revenues it collects in a given year with its Commission-approved revenue requirement and adjusts its rates to recover or refund the difference over the following year. Under "partial decoupling," actual revenues are weather normalized before the decoupling adjustment is calculated.

In Xcel's last rate case, the Commission approved full revenue decoupling for the Company's Residential and Small Commercial customer classes as a three-year pilot program.¹⁶ The decoupling pilot program included a three percent cap on any upward rate adjustment, with a provision allowing Xcel to recover costs barred by the cap in succeeding years under certain conditions.

In this case, the Settling Parties propose to extend the decoupling pilot program by one year—through 2019—to match the term of the Settlement, and to use partial decoupling (i.e., sales true-ups based on weather-normalized data) in 2017–2019 for commercial and industrial customers who are not part of the full-decoupling pilot. Similar to the pilot program, any resulting rate increases to the partially decoupled classes would be capped at three percent.

3. Authorized ROE and Cost of Capital

In setting rates, the Commission must consider a utility's need for revenue sufficient to enable it to meet the cost of furnishing service, including a fair and reasonable return on investment.¹⁷ One of the critical components of that fair and reasonable return on investment is the return on common equity (ROE), which, together with debt, finances the utility infrastructure.

The Settlement proposes that the Commission "allow Xcel Energy to represent its authorized ROE as nine and two-tenths percent (9.20%) for settlement purposes in this rate case Proceeding."¹⁸

The ROE figure has no effect on the Settlement's proposed revenue requirement, but it would allow Xcel to represent to financial markets that its authorized ROE is 9.2%, and to use this figure to initially calculate proposed rates for riders. Xcel acknowledged that the Settling Parties are free to advocate for a different ROE in future dockets and that the Commission may review ROE on a case-by-case basis in relevant dockets.

Xcel's overall cost of capital is derived from the sum of costs for long-term debt, short-term debt, and equity, weighted by the amount of each type of financing employed. The Settling

¹⁶ See *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. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 77 (May 8, 2015).

¹⁷ Minn. Stat. § 216B.16, subd. 6.

¹⁸ Stipulation of Settlement, at 6.

Parties agreed that Xcel should be allowed to represent its capital structure as set forth in the following tables:

	2016			2017		
	Rate	Ratio	Wtd. Cost	Rate	Ratio	Wtd. Cost
Short-Term Debt	1.84%	1.26%	0.02%	3.57%	1.46%	0.05%
Long-Term Debt	4.81%	46.24%	2.22%	4.81%	46.04%	2.21%
Common Equity	9.20%	52.50%	4.83%	9.20%	52.50%	4.83%
Total			7.07%			7.09%

	2018			2019		
	Rate	Ratio	Wtd. Cost	Rate	Ratio	Wtd. Cost
Short-Term Debt	4.45%	1.09%	0.05%	4.31%	1.69%	0.07%
Long-Term Debt	4.77%	46.41%	2.21%	4.75%	45.81%	2.18%
Common Equity	9.20%	52.50%	4.83%	9.20%	52.50%	4.83%
Total			7.09%			7.08%

4. Customer Protections

Xcel confirmed that it would continue to file annual reports “with its actual recorded jurisdictional financials and earnings to provide transparency in its financial performance.”¹⁹ Further, the Settlement expressly recognizes the Commission’s authority, under the multiyear-rate-plan Statute, Minn. Stat. § 216B.16, subd. 19(e), to examine the reasonableness of Xcel’s rates during the term of its multiyear rate plan and to adjust those rates as necessary.

Xcel and the Department also maintained that Xcel would continue the practice, approved in the Company’s last rate case, of performing a capital-projects true-up. In that case, the Commission approved a mechanism under which the Company would provide customers a refund if actual capital-project revenue requirements were lower than those included in rates.²⁰

5. Provisional Recovery of Prairie Island Life-Cycle Management Costs and Use of Nuclear Expert

At the outset of Xcel’s rate case, the Commission ordered that the record be developed on life-cycle management costs related to the Company’s Prairie Island nuclear power plant, and whether such costs should be recovered on a provisional basis until such time as the Commission could review their prudence. It also authorized the Department to engage an expert to aid in this effort.

¹⁹ Burdick Rebuttal, at 5; See Minn. R. 7825.4700–.5400.

²⁰ See *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. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 105 (May 8, 2015). In 2014, the true-up was calculated based on aggregate spending, while in 2015, it was calculated on a project-by-project basis. The Settlement adopts the aggregate-spending method used in 2014. The capital-spending true-up is one-way, meaning that the Company will make refunds if it spends less than it budgeted but cannot increase rates if it spends more.

The Settlement acknowledges that its proposed rate increases include Prairie Island life-cycle management costs and other nuclear capital costs. The Settling Parties agreed that there was no need for expert review of these costs at this time. They proposed instead that the Department retain a nuclear expert in Xcel's next resource-planning proceeding to examine the continued cost-effectiveness of the Company's nuclear fleet and evaluate the Company's planned capital and operations and maintenance (O&M) expenses, with the understanding that Xcel will continue to carry the burden of demonstrating the reasonableness of future rate increases.²¹

6. Interim-Rate Refund

The Settlement provides that Xcel will apply its cost of long-term debt (4.81 percent) to any interim-rate refund ordered by the Commission.

7. Deferral of 2016 Property Taxes

The Settling Parties agreed that Xcel would defer as a regulatory asset in 2016 an amount equal to the difference—not to exceed \$28 million—between the property-tax expense approved for recovery in base rates in the Company's last rate case and its actual 2016 property-tax expense, and amortize the deferral evenly over a two-year period in 2018 and 2019.

The deferral is for accounting purposes only and would not impact the rate increases provided for in the Settlement.

8. Bill-Pay Assistance for Customers with Medical Needs

The Settling Parties agreed with ECC's proposal to use POWER ON, Xcel's existing bill-payment-assistance program for low-income ratepayers, as a model in developing a new bill-payment assistance program for medical-needs customers. The new program would do the following:

- Provide an affordability credit to limit the percentage of household income spent on electricity;
- Provide an arrearage-forgiveness component;
- Set income eligibility at 50 percent of the state median income, increasing to 60 percent if sufficient funds are available;
- Provide assistance on a first-come, first-served basis until program resources are exhausted;
- Cap administrative costs at five percent of the annual budget;
- Follow the reporting and program-funding-tracking procedures of POWER ON; and
- Recover program costs on the same basis as POWER ON.

²¹ At hearing, Xcel confirmed that the Settlement does not provide for deferral of Prairie Island costs that are not recovered through the rates set in this case.

9. LED Street Lighting

The Settling Parties agreed to remove from this rate case all revenue requirements arising from capital additions for light-emitting diode (LED) streetlights and to use the lowered revenue requirement in setting final street-lighting rates.

Xcel would defer as a regulatory asset the revenue requirements directly related to actual LED-streetlight capital additions during the term of the Settlement, without interest, and credit LED street-lighting revenues against the deferral.

Minneapolis and the SRA agreed not to contest Xcel's recovery of the deferral in its next rate case but reserved the right to challenge the Company's claimed costs, alleged savings, and any other aspect of street-lighting rates.

10. Fuel-Clause Adjustment

The Settling Parties agreed that Xcel's Fuel Clause Adjustment mechanism (FCA), which the Company uses to recover the costs of fuel and purchased power, would be addressed according to the Commission's previous orders in the following dockets: E-999/CI-03-802, E-999/AA-12-757, E-999/AA-13-599, and E-999/AA-14-579.

11. Comparison of Company-Proposed, Department-Recommended, and Settlement Revenue Requirements

The table below compares the yearly revenue deficiencies for 2016–2019 as initially proposed by Xcel to the deficiencies calculated by the Department and to those ultimately reflected in the Settlement.

(000s)	2016	2017	2018	2019
Xcel Proposed	\$194,612	\$246,666	\$297,133	\$379,622
Department	\$45,558	\$99,406	\$94,363	\$189,049
Settlement	\$74,990	\$134,850	\$134,850	\$184,970

C. Issues Fully Resolved by the Settlement

Attachment 4 to the Settlement is titled "Issues Resolved for Settlement Purposes" and identifies 60 issues that the Settling Parties resolved among themselves. Most items are not explicitly resolved in the Settlement; the Settlement proposes a revenue requirement but does not establish specific adjustments to the Company's initially-proposed costs to reach its revenue requirement.

A subset of the 60 issues resolved among the Settling Parties were also not contested by any nonsettling party. The Commission considers these issues to be fully resolved by the Settlement:

- Overall Revenue Requirements
- Indexed ROE, Earnings Test, and Sharing Mechanism
- Sales Forecast and True-up
- Overall Operations and Maintenance (O&M) Expenses and Use of Escalators
- Energy Supply O&M Expenses

- Nuclear Non-Outage O&M Expenses
- Prairie Island Life-Cycle Management Capital Costs
- Prairie Island Spent-Fuel Storage Capital Costs
- Prairie Island Settlement Payments
- Prairie Island Reactor Coolant Pump Seals
- Monticello Spent Fuel Storage Capital Costs
- Monticello Cask 16
- Accumulated Deferred Income Taxes (ADIT)
- North Dakota Investment Tax Credits and Research and Experimentation (R&E) Tax Credits
- Minnesota Research and Experimentation (R&E) Tax Credits
- Protecting Americans from Tax Hikes (PATH) Act of 2015
- Property Taxes and True-up
- Health and Welfare Expenses
- Annual Incentive Plan Expenses
- 401 Nicollet Mall Building
- Cost Allocations – Transco Amortization
- Cost Allocations – Service Company
- Depreciation – Update for Remaining Lives Docket
- Changes to In-Service Dates – Transmission Projects
- Changes to In-Service Dates – Prairie Island Fire Protection
- Changes to In-Service Dates – Mankato Energy Center II
- Reclassification of Interruptible Sales to Firm
- Non-Asset-Based Trading
- Transmission Studies
- Courtenay Wind Land Lease
- Other Revenues – Three-Year Average
- Revenue Requirement for Fuel and Purchased Fuel
- MCC and EEI Dues (Lobbying)
- Rate-Case Expense Amortization
- Annual Compliance Filings on Cost of Debt and Capital Structure
- Interest Synchronization and Cash Working Capital
- Riders During Multiyear Rate Plan
- Capital Projects True-up
- Fuel Clause Adjustment
- Low-Income/Medical-Needs Discount Program
- LED Street Lighting

- Billing Format Issues
- Service Reliability (Non Revenue Requirements)
- Key Performance Indicators and Incentives
- Bill Documentation for Manual Bills

D. Issues Not Fully Resolved by the Settlement

AARP recommended that the Commission reject the Settlement or modify it significantly, arguing that it did not provide sufficient protections for consumers. The OAG, while not recommending that the Commission reject the Settlement, requested that if the Commission adopts the Settlement, it modify the Settlement's ROE and make findings on other issues the OAG raised.

The following issues, contested by the OAG, AARP, or both, were not fully resolved by the Settlement:

- Return on Equity
- Overall Cost of Capital
- Capital Budgeting
- Construction Work in Progress (CWIP)/Allowance for Funds Used During Construction (AFUDC)
- Business Systems – Productivity Through Technology (PTT) Expenses
- Employee Expenses
- Executive Compensation
- Revenues From Asset-Based Sales
- Interest Rate on Interim Rate Refund
- Depreciation-Reserve Amortization
- Wholesale Jurisdictional Allocation
- Nuclear Refueling Outage Accounting
- Length of Multiyear Rate Plan
- Performance Metrics
- Extension of Decoupling Pilot Program

E. Summary of Commission Action on Settlement

In the sections that follow, the Commission examines each objection to the Settlement maintained by a nonsettling party. In each case, the Commission concludes that the objection (1) is without merit and/or (2) does not justify disturbing a Settlement that, as a whole, will result in just and reasonable rates.

Finally, the Commission discusses the factors that led it to conclude that the Settlement will result in just and reasonable rates and should be approved. In brief, these factors include

- The participation of several sophisticated parties, representing all classes of Xcel's ratepayers, in the Settlement;
- The robust evidentiary record supporting the Settlement's proposed rate increases, revenue requirement, and ROE;
- The Settlement's substantial ratepayer benefits, including predictable increases, a rate freeze in 2018, limitations on the use of riders, and a capital-projects true-up; and
- The Settlement's recognition of the Commission's authority to review and adjust Xcel's rates at any time during the four-year Settlement term.

For these and other reasons discussed below, the Commission concludes that the Settlement is in the public interest and will result in just and reasonable rates.

II. Return on Equity

A. Summary

In determining just and reasonable rates, the Commission must

give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, *and to earn a fair and reasonable return upon the investment in such property.*²²

One of the critical components of that fair and reasonable return upon investment is the return on common equity (ROE). The Commission must set rates at a level that permits stockholders an opportunity to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

In traditional rate cases, determining a fair and reasonable ROE is a necessary step in developing an overall rate of return that, when applied to the utility's rate base, yields a cost of capital that is used to calculate final rates. In contrast to the usual ROE approach, the Settlement proposes a revenue requirement without specifying a rate base and allows Xcel to represent a specified ROE as its authorized ROE. Thus, the Settlement ROE has no effect on final rates.

Having an authorized ROE is valuable to Xcel because it allows the Company to represent to current shareholders and to the broader market that it has the ability to earn this return. And, as discussed in more detail later, Xcel also uses its authorized ROE in calculating costs recovered through certain riders, and in computing AFUDC.²³

²² Minn. Stat. § 216B.16, subd. 6 (emphasis added).

²³ Allowance for Funds Used During Construction, or AFUDC, is an accounting procedure by which the financing costs of funds used for construction are treated as income for purposes of offsetting rate-base treatment of the costs of construction work in progress.

Three of the Settling Parties—Xcel, the Department, and XLI—filed ROE analyses before joining the Settlement. The OAG filed testimony contesting the ROE set by the Settlement, and AARP concurred in the OAG’s recommendation.

In the remainder of this section, the Commission evaluates the evidence on ROE and concludes that the Settlement’s ROE of 9.20 percent is reasonable and supported by the record.

B. The Analytical Tools

Xcel is a subsidiary of Xcel Energy, Inc. and has no publicly traded common stock. Its ROE must therefore be inferred from market data for groups of companies that present similar investment risks, or “proxy groups.”

Xcel, the Department, XLI, and OAG conducted cost-of-equity studies and based their analysis on proxy groups they considered similar enough to Xcel to serve as substitutes in determining the Company’s cost of equity. All four parties used the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance.

All four parties also used the Capital Asset Pricing Model (CAPM) as a secondary, corroborating resource, consistent with the Commission’s historical treatment of this model. The Company also conducted a third analysis using the Risk Premium Model, which the Commission has historically relied on less heavily, considering the model prone to producing volatile and unreliable outcomes.

The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, stock prices, and growth rates. DCF modeling can be performed using constant-growth, two-growth, or multistage dividend-growth assumptions.

The CAPM model estimates the required return on an investment by determining the rate of return on a risk-free, interest-bearing investment and adding a historical risk premium determined by subtracting that risk-free rate of return from the total return on all market equities and multiplying the difference by beta, a measure of the investment’s volatility compared with the volatility of the market as a whole.

The Risk Premium model determines the cost of equity by adding to current bond yields a premium reflecting the greater returns realized by equity holders over various historical periods.

C. Positions of the Parties

1. The Company

Before it entered into the Settlement, Xcel recommended a return on equity of 10.0 percent, based on a broad range of estimates from 8.95 percent to 11.39 percent generated by its analytical models and input assumptions.

The Company conducted a constant-growth DCF analysis, using a proxy group of 13 electric utility companies screened for comparability with Xcel in terms of operating profiles and investment risks. It obtained growth rates from three nationally recognized investment-research

firms and applied those growth rates to the companies' average stock prices for the historical 30-, 90-, and 180-day periods ending September 30, 2015.

Xcel also performed a multistage DCF analysis, using near-term growth rates from the same three research firms and a long-term growth rate derived from forecasts of GDP growth and inflation. The Company performed a CAPM analysis, using 30-year Treasury bonds as the risk-free asset the analysis requires. And it performed a Risk Premium analysis, again using 30-year Treasury bonds as the baseline asset.

Xcel advocated that factors specific to its operating environment, including rising interest rates and planned capital investments, be considered in the development of ROE. The Company expects to make capital investments of approximately \$6 billion between 2015 and 2019; it asserted that this projected spending, as a percentage of net utility plant, is higher than nine of the companies in its proxy group and higher than the median. These projected expenditures, it argued, add additional risk that requires a higher ROE.

2. The Department

The Department recommended a return on equity of 9.06 percent prior to joining the Settlement.

The Department conducted constant-growth and two-growth DCF analyses, using two proxy groups: an electric proxy group of 6 companies and a combination proxy group of 12 companies.²⁴ The Department used many of the same screening criteria as Xcel to arrive at its proxy groups. In addition, the Department applied a final screen to eliminate companies with an ROE of less than seven percent.

In contrast to Xcel, who used stock prices over three separate periods in 2015, the Department estimated share prices for its proxy companies using the average closing price over the 30 trading days ending May 26, 2016. The Department asserted that this period was long enough to avoid short-term volatility in stock while short enough to reflect recent market information.

Finally, the Department conducted CAPM and Empirical CAPM²⁵ analyses as a check on the reasonableness of its DCF analysis. Unlike Xcel, which used 30-year Treasury bonds as its riskless asset, the Department used 20-year Treasury bonds. The Department concluded that the results of its CAPM and Empirical CAPM analyses confirmed the reasonableness of its two-growth DCF results.

3. OAG

The OAG initially recommended a return on equity of 7.38 percent, the midpoint of its multistage DCF results. The OAG also performed constant-growth DCF and CAPM analyses as checks on the reasonableness of its multistage DCF analysis.

²⁴ The combination proxy group comprised companies engaged in providing electric services in combination with other services, with electric services the major part though less than 95 percent of the total.

²⁵ Empirical CAPM is a method that attempts to adjust for the fact that CAPM tends to underestimate the ROE for companies with a beta smaller than one.

The OAG's initial proxy group was identical to Xcel's, although in rebuttal testimony it updated its group to exclude four companies that had recently announced merger and acquisition activity. The OAG opposed the Department's use of a combined proxy group, arguing that the ROE analysis should be focused on the risks of electric utilities. And it also disagreed with the Department's seven percent ROE screen, arguing that it improperly inserted the analyst's judgment into the analysis.

The OAG updated its ROE analysis in surrebuttal testimony using more recent market data, resulting in somewhat lower ROE estimates. It argued that, had Xcel and the Department performed a similar update, their analyses would also have shown a reduced ROE.

The OAG opposed Xcel's and the Department's use of flotation-cost adjustments in their ROEs. Flotation costs are the costs of issuing new shares of common stock, including preparation, filing, underwriting, and other expenditures. The OAG argued that the adjustments were not appropriate because Xcel did not issue any shares in 2015 and had no planned issuances for 2016–2018.

Finally, the OAG argued that the Settlement's 9.20 percent ROE was not tied to the record and expressed concern about its impact on ratepayers through riders and AFUDC. While the Settlement ROE would have no effect on Xcel's revenue requirement in this case, the Company uses its authorized rate of return to calculate costs collected from ratepayers through certain riders. Moreover, the OAG argued that the Settlement ROE, if applied to AFUDC, would overinflate Xcel's rate base.

For these reasons, if the Settlement is adopted, the OAG recommended that the Commission modify the Settlement's authorized ROE by lowering it from 9.20 percent to as low as 7.07 percent, but ultimately no higher than 8.14 percent. Alternatively, the OAG recommended that the Commission set a lower ROE for use in riders and the computation of AFUDC.

4. XLI

XLI's analysis resulted in an ROE range between 8.7 percent and 9.9 percent, with a midpoint of 9.3 percent. XLI recommended that if the Commission approves a multiyear rate plan, it set the Company's ROE below XLI's midpoint of 9.3 percent because a multiyear rate plan would reduce Xcel's risk.

XLI criticized Xcel's 10.0 percent ROE proposal, arguing that it relied too heavily on the Company's Risk Premium and CAPM analyses and gave insufficient weight to the traditional DCF analysis.

Like the OAG, XLI did not include flotation costs in its ROE analysis because Xcel would not be issuing stock in 2016–2019.

5. AARP

AARP did not perform an analysis of Xcel's ROE. It filed rebuttal testimony opposing the ROE set in the Settlement, arguing that 9.20 percent was too high, particularly in light of the OAG's recommended ROE of 7.38 percent.

D. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the Settlement's authorized ROE of 9.20 percent was reasonable and supported by the record. But he recommended that, if the Commission does not approve the Settlement, it set an ROE based on the Department's analysis, which the ALJ found to be the most reasonable and best supported by the evidence.

1. Evaluation of Record Evidence on ROE

The ALJ determined, consistent with previous Commission decisions, that DCF modeling provided the best resource for determining a reasonable cost of equity. He found that only the Department used the CAPM analysis in the manner traditionally used in a utility rate case—to assess whether the CAPM results fall within the range of DCF results and thereby confirm the reasonableness of the DCF analysis.

The ALJ found that the parties had assembled appropriate proxy groups and screens. He rejected the OAG's argument that the Department's seven percent screen was unreasonable, noting that the OAG's ROE is an outlier compared to ROEs approved in other jurisdictions, falling below any authorized ROE for an electric utility in the United States in the past 30 years.

The ALJ found that the Department's market data were approximately four months older than the data the OAG used in surrebuttal. However, he found that the Department's data were reasonably updated and acceptable for use in ROE analysis—particularly in the context of a multiyear rate plan, where even the most recent market information will no longer be current by the end of the plan's term, and avoiding data that reflect anomalous market conditions becomes a more important consideration.

The ALJ rejected Xcel's argument that projected company-specific or market-wide risks warranted an upward adjustment to ROE. He noted that both Xcel and the Department used S&P credit ratings as screens for their proxy groups and reasoned that S&P could be expected to assess capital-expenditure plans and associated risk in its assessment of utilities' creditworthiness. Further adjusting ROE for company-specific risks would therefore double-count those risks.

Finally, the ALJ recommended a 0.10 percentage-point downward adjustment to the Department's recommended ROE to remove flotation costs. He observed that the Commission in recent rate cases had denied flotation costs where companies had no current plans to issue stock and had not provided evidence of an ongoing financial impact from earlier stock issuances.

2. Reasonableness of Settlement ROE

The Administrative Law Judge found the Settlement's ROE reasonable and supported by the record, finding that it was below the Company's currently authorized ROE of 9.72 percent and below the 2016 average of ROE decisions for vertically integrated utilities.

The ALJ concluded that the OAG's recommended ROE would not provide Xcel with a fair opportunity to earn a reasonable return throughout the term of the Settlement. He found that the OAG's ROE was not representative of returns set by the Commission and other regulatory bodies, both recently and in the past several decades.

Furthermore, the ALJ found that lowering the Settlement ROE, as advocated by the OAG, would likely be viewed by Xcel as having a material adverse impact and cause the Company to withdraw from the Settlement. He reasoned that lowering Xcel's authorized ROE would adversely impact its evaluation by credit-rating firms and current and prospective shareholders. And he similarly concluded that setting a lower ROE for purposes of riders and computing AFUDC would have a material adverse impact on the Company.

The ALJ found that the Settlement permits the Settling Parties to argue that an ROE other than the Settlement's authorized ROE should be used in other proceedings involving the Company, providing some protection if future circumstances point to a lower ROE as being appropriate. And he found that the OAG and AARP, as nonsettling parties, will be free to challenge ROE in future proceedings in any event.

E. Commission Action

The Commission concurs with the ALJ that the Settlement's authorized ROE of 9.20 percent is reasonable and supported by the record.

The Settlement ROE is below the Xcel's currently authorized ROE of 9.72 percent and below the 2016 average of ROE decisions for vertically integrated utilities. It is close to the Department's pre-Settlement recommendation of 9.06 percent. And it is within the ranges of Xcel's and XLI's ROE results, falling near the bottom of Xcel's 8.95–11.39 percent range, and just below the midpoint of XLI's 8.7–9.9 percent range.

The Commission agrees with the ALJ that, of the ROE analyses offered by the parties, the Department's is the most reasonable and best supported by the record evidence. The Settlement ROE is firmly supported by the Department's analysis.

While the four parties presenting evidence on ROE generally applied widely accepted analytical methods in an appropriate manner, only the Department performed consistently sound analyses in reaching its ROE recommendation. The Department used data from established investment-research firms. It applied the latest market data available at the time it submitted direct testimony. It eliminated from its proxy groups companies with ROEs too low to reasonably represent the risk of investing in an electric utility. And it applied its CAPM analysis purely as a check on the reasonableness of its primary, DCF analysis.

The Settlement's ROE is significantly higher than the OAG's recommended range of 7.07–8.14 percent. However, the OAG fails to explain how its recommendation is reasonable or supportable in light of the overwhelming evidence of the range of reasonable ROEs in the record. The Commission finds that an ROE in the OAG's recommended range would not permit Xcel to earn a return sufficient to induce investors to purchase company stock, given the risk associated with investing in an electric utility.

The OAG recommended that the Commission modify the Settlement by lowering the authorized ROE. Alternatively, it recommended that the Commission set a lower ROE for use in riders and the computation of AFUDC.

While modifying the Settlement ROE would have no effect on the proposed rate increases, it could adversely impact Xcel's evaluation by credit-rating firms and current and prospective shareholders. And setting a lower ROE for purposes of riders and AFUDC would directly affect

the costs Xcel is allowed to recover in those contexts. The Commission thus concludes that either modification would likely prompt Xcel to withdraw from the Settlement, necessitating further, costly contested-case proceedings.

More importantly, the OAG's recommendation to modify the Settlement ROE is not reasonable because the OAG's recommended ROE is not supported by a preponderance of the evidence on the record. Because the Settlement does not prevent any party from contesting the ROE when it is applied in rider dockets or other proceedings, if future circumstances suggest that a lower ROE is appropriate in other contexts, parties will be free to assert an alternative ROE at that time.

For the foregoing reasons, the Commission finds the Settlement's 9.20 percent ROE reasonable.

IV. Performance Metrics

A. Introduction

Under Minn. Stat. § 216B.16, subd. 19, the Commission may require a utility proposing a multiyear rate plan to provide a “set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies.”²⁶ Alternatively, the Commission “may initiate a proceeding to determine a set of performance measures that can be used to assess a utility operating under a multiyear rate plan.”²⁷

Xcel's existing performance metrics are set forth in its Quality of Service Plan (QSP) Tariff. The QSP Tariff is the product of negotiations with the Department, the OAG, and the SRA, and has been approved by the Commission. It is penalty-based and tracks eight metrics, including reliability, customer complaints, call response time, billing accuracy, and others.

The Settlement does not propose any new performance metrics. However, prior to settling, Xcel proposed new performance metrics addressing customer satisfaction, customer choice, environmental stewardship, and customer outage experience. The Company did not propose to tie its performance under these categories to any financial penalties or incentives.

B. Positions of the Parties

The Department argued that, before a new performance metric can be evaluated, much more detail needs to be provided about what exactly would be measured, how the data are to be collected, and what behaviors are being targeted for change. It recommended that the Commission open a separate proceeding to evaluate Xcel's proposed metrics, craft additional metrics, and consider whether to tie any financial penalties or incentives to the Company's performance under those metrics.

The OAG, similarly, recommended that the Commission initiate a proceeding to determine a set of performance metrics that can be used to assess a utility operating under a multiyear rate plan, as specified by statute.

²⁶ Minn. Stat. § 216B.16, subd. 19(a).

²⁷ *Id.*, subd. 19(h).

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found the record insufficient to support the establishment of any new performance metrics for the multiyear rate plan. He recommended that the Commission open a separate proceeding to examine appropriate metrics and consider linking the metrics to financial penalties or incentives.

D. Commission Action

The Commission concurs with ALJ and will open a separate docket to identify and develop performance-based metrics and standards—and potentially incentives—to be implemented during the multiyear rate plan.²⁸ The Commission will delegate to its Executive Secretary authority to issue notices, set a schedule, and designate comment periods for the docket.

Performance metrics are an important tool to preserve service quality and align utility incentives with ratepayer interests, particularly in the context of a Settlement that establishes rate increases for multiple years. However, the record in this case is not sufficiently developed to determine the adequacy of Xcel's proposed performance metrics—or what other measures of performance might be established in place of or in addition to Xcel's metrics.

Moreover, the Commission is not satisfied, on this record, that the Company has given full consideration to the potential for coupling performance metrics with financial incentives. The Commission concludes that a new docket will provide the best venue for determining what combination of metrics and incentives, in addition to those already in Xcel's QSP Tariff, would appropriately align utility and ratepayer interests.

V. Extension of Decoupling Pilot Program

A. The Issue

As discussed, the Settlement would extend by one year the decoupling pilot program established for Residential and Small Commercial customer classes in Xcel's last rate case.

AARP argued that extending the decoupling pilot program by a year would deny consumers the reassurance that data from the current pilot would be reviewed before a decision is made to extend the program. More specifically, it argued that decoupling shifts risks to ratepayers, insulates the utility from the risk of declining sales, causes high-usage customers to subsidize low-usage customers, and rewards the utility for energy savings it did not bring about. AARP advocated that decoupling surcharges be capped at two percent to preserve affordability.

The Administrative Law Judge deemed AARP's concerns sensible but reasoned that the Commission had already weighed these concerns along with others when it approved the three-year decoupling pilot. He found it reasonable to extend the decoupling pilot to match the term of the Settlement.

²⁸ *In the Matter of a Commission Investigation to Identify and Develop Performance-Based Metrics, and Potentially Incentives, for Xcel Energy's Electric Utility Operations*, Docket No. E-002/CI-17-401.

B. Commission Action

The Commission agrees with the ALJ that extending the decoupling pilot program by one year to match the term of the Settlement is reasonable and adopts his findings and conclusions on this issue. Making the term of the pilot program co-extensive with the four-year term of the Settlement will conserve Commission, party, and ratepayer resources by allowing the pilot to be evaluated at the same time as Xcel's next rate case, should it choose to file one at the conclusion of the four-year Settlement term.

Moreover, the Commission has already determined that the decoupling pilot program has sufficient ratepayer protections, including customer education and outreach requirements, annual reporting requirements, and a three percent cap on upward adjustments to the rates of any single customer class. The Settlement leaves these existing protections in place for the extra year that the pilot is in effect.

VI. Capital Budgeting

A. The Issue

A substantial portion of the rate increases proposed under the Settlement are driven by anticipated capital spending.

The OAG contended that Xcel has a history of significantly overestimating its capital spending, claiming that the Company's 2015 budget overstated actual capital investments by 21 percent. The 2015 overbudgeted amount was refunded to ratepayers under the capital-projects true-up ordered in the Company's last rate case.²⁹

The OAG argued that Xcel needs an incentive to budget more accurately.

Xcel disputed the OAG's claim that its 2015 capital-project costs exceeded estimates by 21 percent. It argued that the cost difference was primarily due to projects being completed later than expected. And it maintained that the true-up mechanism worked as intended, providing customers with a refund plus interest due to the project timing differences.

The Administrative Law Judge found that the four-year rate plan established by the Settlement poses some difficulty for capital budgeting, in that unexpected events can occur that require a redeployment of resources to provide safe and reliable service. However, he found that ratepayers would be protected from overbudgeting through the Settlement's capital-projects true-up provision.

B. Commission Action

The Commission agrees with the Administrative Law Judge that the capital-projects true-up will provide ratepayers with significant protection against capital-spending overbudgeting. And while the record is not sufficiently developed to adopt the OAG's recommendation for a budget-

²⁹ See *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. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 108 (May 8, 2015).

accuracy incentive, such an incentive could be considered in the proceeding to explore potential performance metrics and incentives discussed in section III above.

Xcel's budget for 2016–2018 includes approximately 1,810 capital projects. In contrast to some past rate cases, there are not many extremely large projects planned; Xcel estimates that the largest 335 discrete projects account for approximately 90 percent of the total anticipated spending.

Under these circumstances, the aggregate spending data used in the capital-projects true-up will provide little indication of cost over- or under-runs that may occur on individual projects. While there may be too many projects in Xcel's capital budget to require reporting at the per-project level, it would be beneficial, for regulatory-review purposes, to have the Company file more information about its capital projects than just the overall spending in a given year.

Accordingly, the Commission will direct Xcel to work with Commission and Department staff to develop an annual capital-projects true-up compliance report that meets the regulatory needs of the agencies. This will allow the agencies to review Xcel's capital spending at a more granular level while considering ways to ease the administrative burden of reporting on 1,810 capital projects.

VII. Construction Work in Progress (CWIP) / Allowance for Funds Used During Construction (AFUDC)

A. Introduction

Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC) are accounting devices used to permit utilities to recover the financing costs of capital projects while they are under construction. The Commission is authorized to consider CWIP and AFUDC in ratemaking under Minn. Stat. § 216B.16, subds. 6 and 6a.

Capital costs incurred during construction are placed in rate base as CWIP; the associated financing costs are added to net operating income as AFUDC, normally offsetting any return on CWIP until the plant under construction goes into service. At that time, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense.

The Commission has been following this approach in Xcel rate cases since 1977.

B. Positions of the Parties

The OAG argued that the rate of return that Xcel receives on AFUDC results in the Company's retail rates being among the highest in the region. To better protect ratepayers, the OAG made three recommendations:

- First, the OAG recommended that the rate of return allowed on AFUDC should either be calculated as a 50/50 blend of short- and long-term interest rates on debt or be set at the prime rate.
- Second, it recommended that the Commission follow the Federal Energy Regulatory Commission's (FERC's) prohibition against allowing AFUDC to be accrued on projects that have been dormant three months or longer "unless the Company can justify the interruption as being reasonable under the circumstances."

- Third, the OAG recommended that the Commission prohibit AFUDC on construction projects budgeted at less than \$5 million.

Xcel contended that it does comply with FERC's rules with respect to AFUDC. It maintained that the Commission has repeatedly approved the inclusion of AFUDC and CWIP in rate cases and has explicitly rejected similar recommendations by the OAG in recent cases, and it argued that the OAG had not presented the Commission with new information or arguments for changing course.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed that the Settlement is consistent with the Commission's past practice with respect to CWIP and AFUDC, and that the OAG had not presented new evidence or argument for changing that practice. He therefore found the Settlement's treatment of CWIP and AFUDC reasonable.

D. Commission Action

The Commission agrees with the ALJ that the Settlement's treatment of CWIP and AFUDC is reasonable and adopts his findings and conclusions on this issue.

The OAG has not advanced any new arguments or evidence to support its AFUDC proposals. Moreover, the alternative to AFUDC is directly expensing interest costs, which has a larger immediate impact on rates than capitalizing the costs. Xcel estimated that, due to the amount of CWIP in its rate base that is now offset by AFUDC, the OAG's proposal would increase the Company's revenue requirement for 2016 by \$19.3 million.

Under the circumstances, the Commission will decline to depart from established practice with respect to CWIP and AFUDC.

VIII. Business Systems – Productivity Through Technology (PTT) Expenses

“Productivity Through Technology” refers to Xcel's efforts to replace its General Ledger and several Work and Asset Management Systems that have reached the end of their useful lives. Xcel originally included \$131.5 million in rate base for PTT projects, \$4.2 million in PTT-related operation and maintenance (O&M) expenses in the 2016 test year, and significant PTT depreciation expense in the test year and the 2017 and 2018 plan years.

The OAG argued that Xcel should reduce its PTT expenses by the savings realized through PTT projects. It reasoned that, since ratepayers are paying the cost of PTT-related plant additions, depreciation, and O&M, they should receive the cost savings generated from these initiatives.

Xcel acknowledged that efficiencies from PTT projects allow the Company to avoid additional O&M costs that it would otherwise incur; however, Xcel argued that projected savings from PTT are already reflected in the test-year budget.

The ALJ found that Xcel had not met its burden to show that its budget took into account cost savings from PTT, reasoning that the Company should be able to more precisely quantify the savings that will result from such a significant investment. However, the ALJ did not recommend rejecting the Settlement over the issue of PTT savings.

The Commission concurs with the Administrative Law Judge and adopts his findings and conclusions on this issue. While Xcel should be able to better quantify the expected savings from PTT, the Commission agrees that this is not a sufficient basis to reject or modify a settlement that, on the whole, results in just and reasonable rates.

IX. Employee Expenses

Minn. Stat. § 216B.16, subd. 17(a), bars the recovery of employee travel and entertainment expenses that the Commission deems unreasonable and unnecessary for the provision of utility service.

The Settlement does not explicitly include an adjustment for employee expenses. However, Xcel initially included \$15,041,247 in employee travel and entertainment expenses in its 2016 test year.

The OAG argued that the Commission should disallow certain travel and entertainment expenses because they were unnecessary for the provision of utility service. The expenses that the OAG objected to related to a work celebration, regularly scheduled department meals, voluntary employee social clubs, and individual coaching sessions. The OAG initially recommended disallowing \$76,027 in employee expenses.

In its rebuttal testimony, Xcel agreed to remove roughly a third of the amount that the OAG recommended be excluded, and the OAG dropped certain disputed items. Following these adjustments, some \$25,622 in 2016 test-year employee expenses remained in dispute.

The Administrative Law Judge found that the challenged expenses were related to Xcel's operations and were not unusual or extraordinary for an established business. He noted that the Settlement reflects a substantially reduced overall revenue requirement and reasoned that this reduction would cause the Company to revise its budgets and reduce expenses, including employee expenses. Consequently, he recommended no adjustment to travel and entertainment expenses if the Commission approves the Settlement.

The Commission concurs with the Administrative Law Judge that no adjustment to the Settlement is warranted based on the disputed employee expenses. The Commission will adopt the ALJ's findings and conclusions on this issue.

X. Executive Compensation

Xcel's revenue requirement included compensation expenses for Benjamin Fowke, the CEO of Xcel, and Chris Clark, the president of Xcel for Minnesota, South Dakota, and North Dakota.

The OAG recommended that the Commission disallow 100 percent of Mr. Fowke's compensation and expenses and 50 percent of Mr. Clark's compensation and expenses, arguing that these percentages of their compensation are directed solely to increasing earnings, which does not benefit ratepayers.

Xcel challenged the OAG's assertion that its executives focus their efforts on increasing earnings and argued that, in any event, the Company's earnings contribute to its financial health, which benefits ratepayers by allowing the utility access to capital markets on favorable terms and lowering the overall cost of service. Xcel also presented evidence that its executives are paid at or below market levels, which the OAG did not dispute.

The ALJ concluded that executive services, like any other expense, must be obtained at a reasonable cost to be recoverable. He found that the OAG did not provide a basis for distinguishing between executive time that increased earnings without any collateral benefit to ratepayers and executive time that did provide a collateral benefit. He did not recommend rejecting or modifying the Settlement based on executive compensation.

The Commission concurs with the Administrative Law Judge and will adopt his findings and conclusions on this issue. The executive-compensation amounts appear to be reasonable, and the OAG's arguments are not sufficient to introduce doubt about their reasonableness.

XI. Revenues from Asset-Based Sales

When Xcel has unused or underutilized generation capacity, it seeks to sell power on a wholesale basis to other utilities ("asset-based sales"). In 2015, approximately nine percent of Xcel's sales were to wholesale customers.

The OAG expressed concern that Xcel has recently increased its generation capacity while at the same time contending that sales are stagnant, leading to increased opportunities for asset-based sales. The OAG argued that the Company's test-year revenues for asset-based sales should be increased by \$19.1 million to recognize what, in the OAG's view, was an excessive level of generation capacity.

Xcel responded that the Commission had approved all its capacity additions. As a member of MISO,³⁰ the Company must make its excess capacity available on the MISO market at marginal cost. Xcel stated that it credits ratepayers with 100 percent of the margins from its sales on the MISO market through the Fuel Clause Adjustment rider.

The Administrative Law Judge did not recommend rejecting or modifying the Settlement based on asset-based sales. He found that Xcel is essentially a price-taker, obliged to offer its excess power at marginal cost, and that the OAG had not explained how the Company could increase its wholesale revenues under these circumstances.

The Commission concurs with the Administrative Law Judge that Xcel's asset-based sales amounts are reasonable and will adopt his findings and conclusions on this issue.

³⁰ The Midcontinent Independent System Operator (MISO) operates the upper Midwest transmission system.

XII. Interest Rate on Interim-Rate Refund

A. The Issue

When the Commission orders interim rates into effect during a rate case, but ultimately approves final rates that are lower than interim rates, Minn. R. 7825.3300 requires that the utility refund the difference to its customers, “including interest at the average prime interest rate computed from the effective date of the [interim] rates through the date of refund.” As of May 2017, the prime rate was 4.00 percent.

The Settlement provides for an interim-rate refund with interest at 4.81 percent, which is Xcel’s cost of long-term debt.

The OAG recommended that any refund include interest at a higher interest rate than has historically been used for interim-rate refunds. Specifically, it recommended a rate of 1.5 percent per month, or 18 percent on an annual basis. The OAG argued that such a rate, in addition to making ratepayers whole, would give Xcel an incentive to make more accurate cost projections.

The ALJ found the OAG’s recommended interest rate of 18 percent excessive and found the Settlement’s 4.81 percent rate reasonable.

B. Commission Action

The Commission concurs with the ALJ, will grant a variance to Minn. R. 7825.3300, and will order that an annual 4.81 percent interest rate be used to calculate interim-rate refunds in this case. Applying Minn. R. 7829.3200’s standard for granting rule variances, the Commission finds as follows:

1. Enforcement of Minn. R. 7825.3300 would impose an excessive burden on ratepayers because it would prevent them from receiving a higher interest rate voluntarily offered by the Company.
2. Granting a variance to the rule would not adversely affect the public interest, but in fact would promote the public interest by providing ratepayers with a benefit that no party opposes.
3. Granting the variance would not conflict with standards imposed by law because the Commission is expressly authorized to set the interest rate that applies to interim-rate refunds under Minn. Stat. § 216B.16, subd. 3(c).

Finally, the Commission agrees with the ALJ that the OAG’s recommendation to require an interim-rate refund with 18 percent interest would unreasonably burden Xcel, and would in fact only be an incentive by virtue of being punitive.

XIII. Depreciation-Reserve Amortization

For a time, Xcel underestimated the useful life of certain assets and consequently recorded depreciation expense in excess of the assets’ actual depreciation. The excess recorded depreciation expense gave rise to a “depreciation-reserve surplus,” which, by 2012, had reached \$261 million.

In Xcel's 2012 and 2013 rate cases, the Commission directed the Company to return this depreciation-reserve surplus to ratepayers by amortizing it, initially, over an eight-year period,³¹ and, later, over a three-year period.³² This resulted in a lower annual depreciation expense for the assets at issue than would have occurred without the amortization. However, it also meant that the portion of these assets that remained in rate base, upon which the Company earns a return, was higher than it otherwise would have been.

The OAG recommended that the rate-base increase that resulted from amortizing the depreciation-reserve surplus—or \$261 million—should cease earning a return. The OAG contended to allow this sum to earn a return going forward would be to permit Xcel's shareholders to recover a return on these assets twice.

Xcel argued that the Commission, in ordering amortization of the depreciation-reserve surplus, understood that amortization would reduce rates in the near term but increase rates in future years. By reducing depreciation, the Company recovers its investment more slowly, and shareholders are compensated for this delay by receiving a return on the undepreciated portion of the assets.

The Administrative Law Judge did not find that the amortization of the depreciation-reserve surplus provided a double recovery and did not recommend rejecting or modifying the Settlement on the basis of depreciation reserve.

The Commission concurs with the Administrative Law Judge that Xcel's amortization of its depreciation-reserve surplus was appropriate and does not result in double recovery. The Commission will adopt the ALJ's findings and conclusions on this issue.

XIV. Wholesale Jurisdictional Allocation

In November 2013, a group of wholesale transmission customers filed a complaint with the Federal Energy Regulatory Commission (FERC), which oversees regional energy markets, alleging that MISO transmission owners, of which Xcel is one, were receiving too high a return on equity through their transmission rates. A second complaint was filed by a separate group of customers in February 2015.

Xcel credits its retail customers, through the Transmission Cost Recovery (TCR) rider, with the margins it earns from selling wholesale transmission services. The Company proposed that, if FERC orders a lower transmission ROE, resulting in decreased wholesale transmission revenues, the decrease be reflected in TCR rider rates.

³¹ See *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. E-002/GR-12-961, Findings of Fact, Conclusions, and Order, at 29 (September 3, 2013).

³² See *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. E-002/GR-13-868, Findings of Fact, Conclusions, and Order, at 50–51 (May 8, 2015).

The OAG criticized Xcel's proposal, arguing that the Company's Minnesota retail customers would, in effect, be insuring Xcel against an adverse ROE decision in another jurisdiction. The OAG recommended that Xcel reinstitute its practice of allocating costs between wholesale and retail "jurisdictions," similar to how the Company allocates costs among the states in which it operates.

The Settlement does not require Xcel to reestablish its wholesale jurisdiction. But, the Administrative Law Judge concluded that the OAG had not demonstrated that Minnesota retail customers would benefit from the reestablishment of a separate wholesale jurisdiction, noting that Xcel credits its retail customers with the margins from wholesale services.

The Commission concurs with the Administrative Law Judge that Xcel's proposal to reflect decreased wholesale transmission revenues in the TCR rider is reasonable and adopts his findings and conclusions on this issue.

XV. Nuclear-Refueling-Outage Accounting

Since the conclusion of its 2008 rate case, Xcel has been deferring and amortizing its nuclear-refueling-outage costs. The Commission approved this cost treatment to ensure greater accuracy in cost recovery by reasonably matching the time these costs are incurred with the time they are recovered while avoiding substantial fluctuations between rate cases.

The Commission has in the past approved a carrying charge—calculated at Xcel's overall rate of return—to compensate the Company for the time value of money forgone as part of this deferred recovery. The Settlement does not change the Commission's past practice with respect to the treatment of nuclear refueling costs.

The OAG objected to allowing Xcel to earn its full rate of return on the deferred, unamortized refueling-outage costs. It recommended that either no carrying charge be allowed on these costs, or that only a reduced rate of return be allowed, such as Xcel's cost of short-term debt.

The Administrative Law Judge did not recommend rejecting or modifying the Settlement based on this issue. He recommended that, if the Commission does not approve the Settlement, it consider applying an intermediate-term rate of return to the costs.

While examining the carrying charge for deferred refueling-outage costs may be a worthwhile exercise in a future rate case, the Commission concludes that this is not a sufficient basis to disturb a settlement that, on the whole, results in just and reasonable rates.

XVI. Length of Multiyear Rate Plan

Minn. Stat. § 216B.16, subd. 19, permits a utility to propose a multiyear rate plan of up to five years. Xcel initially proposed both three-year and five-year rate plans; the Settlement would result in a four-year rate plan.

The OAG and AARP both expressed concerns about multiyear rate plans.

The OAG argued that Xcel's multiyear-rate-plan proposals represent a significant change from historical practice, where rates are set based on a company's known and anticipated expenses for a test year. By contrast, under Xcel's rate-plan approach, the Commission's determination of just

and reasonable rates will inform the Company's budget decisions for several years. The OAG argued that this gives Xcel an incentive to minimize its operating budget to maximize shareholder returns; yet ratepayers may not want certain operating expenses, such as maintenance expenses, minimized.

AARP was primarily concerned with what it viewed as the Commission's loss of practical oversight of Xcel's rates during a multiyear rate plan. It argued that the Commission cannot perform a full review of a utility's proposed rates, or provide customer protections, if the utility has "an automatic path" to higher rates with only an annual check-in.

The Administrative Law Judge found that the Settlement's four-year rate plan comported with the Legislature's clear authorization of multiyear rate plans of up to five years. He reasoned that this authorization necessarily entailed that Xcel be allowed to adjust its budgets as necessary to address changing circumstances over the term of the rate plan.

The Commission concurs with the Administrative Law Judge and adopts his findings and conclusions on this issue. While Xcel will not be filing another rate case until at least November 2019, the Commission retains the authority, throughout the term of the multiyear rate plan, to examine the reasonableness of Xcel rates and to adjust them as necessary. The Commission will thus maintain oversight of the Company's rates during the term of the Settlement, allowing it to investigate any claim that the Company is overearning.

XVII. Settlement Approved

A. The Legal Standard

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.³³ Any doubt as to reasonableness is to be resolved in favor of the consumer.³⁴

The Act also encourages settlements. Before beginning contested case proceedings on a general rate case, administrative law judges are required to convene a settlement conference for the purpose of encouraging settlement of some or all of the issues in the case. They are authorized to reconvene the settlement conference at any point before the case is returned to the Commission, at their own discretion or at the request of any party.³⁵

The Commission is authorized to accept, reject, or modify any settlement. It can accept a settlement only upon finding that to do so is in the public interest and is supported by substantial evidence.³⁶

³³ Minn. Stat. § 216B.16, subd. 4.

³⁴ Minn. Stat. § 216B.03.

³⁵ Minn. Stat. § 216B.16, subd. 1a (a).

³⁶ Minn. Stat. § 216B.16, subd. 1a (b).

B. Positions of the Parties

1. The Settling Parties

The Settling Parties agreed that the revenue increases in the Settlement are just, reasonable, and in the public interest. They asserted that the proposed rate increases are moderate, amounting to 6.1 percent, or \$187.97 million, over four years before accounting for the initial 2016 sales true-up. And even with the \$60 million baseline increase that resulted from this initial sales true-up, the Settling parties continued to support the Settlement because of its other benefits, which included a three-percent cap on future sales-true-up-related rate increases, limits on new rate riders, and the guarantee that Xcel would not file another rate case for four years.

2. The OAG

The OAG criticized what it perceived as a lack of record support for the Settlement's revenue requirement, arguing that the did not provide the type of detailed financial information that the Commission typically considers in a rate case, such as a rate base, income statement, and rate of return. And it argued that the rate increase under the Settlement was larger, as a percentage of Xcel's initial request, than the increases approved by the Commission in past rate cases.

The OAG argued that the Commission should not adopt the Settlement without considering the issues raised by nonsettling parties, making specific findings on those issues, and modifying the Settlement where warranted. The OAG did not recommend any specific adjustments to the Settlement's revenue requirement, but it did recommend that the Commission lower the Settlement's authorized ROE or, alternatively, set a lower ROE for use in riders and the calculation of AFUDC.

3. AARP

AARP argued that the Commission should reject the Settlement or significantly modify it to protect Residential customers. It argued that multiyear rate plans create risks for consumers and recommended that the Commission adopt a two-year rate plan rather than the Settlement's four-year plan. And it agreed with the OAG that the Settlement's ROE was too high and argued that there should be a profit-sharing mechanism to protect ratepayers if circumstances later show that a lower revenue requirement is warranted.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Settlement would contribute to establishing just and reasonable rates and that none of the objections to adopting it were sufficient to merit its rejection. He therefore recommended that the Commission approve the Settlement.

The ALJ found the Settlement's overall revenue requirement just and reasonable, finding that it was consistent with the Department's recommended revenue adjustments, including its recommended ROE. He found the Settlement's authorized ROE of 9.20 percent reasonable and supported by the record for the reasons explained in his evaluation of the parties' ROE analyses.

The ALJ also found the yearly rate increases reasonable based on their being less than independent measures of inflation and significantly less than what Xcel initially proposed. He also found it significant that the Settlement proposes no rate increase in 2018 and prohibits Xcel from filing another rate case until November 2019, giving the parties and ratepayers relief from annual rate-case proceedings. And he found that the Settlement provides rate payers further relief by prohibiting the Company from seeking to institute any new riders for four years.

The ALJ concluded that the reasonableness of the Settlement was further supported by ratepayer protections, including true-ups for sales, capital spending, and property taxes. He observed that the capital-spending true-up is one-way, meaning that the Company will make refunds if it spends less than it budgeted but cannot increase rates if it spends more. And he found that the Settlement does not affect the Commission's authority to investigate, examine, and adjust the Company's rates during the term of the plan.

The ALJ rejected the OAG's criticisms of the Settlement. He reasoned that, although the Settlement does not provide an itemization of costs, the record contains substantial evidence of how Xcel developed its proposed cost of service, as well as the Department's recommended adjustments. He found that the Settlement sets a just and reasonable overall limit on rate increases and reasoned that each cost-of-service component need not be separately determined.

Finally, the ALJ rejected AARP's arguments against the Settlement. In particular, he did not find the Settlement's lack of a profit-sharing mechanism or its four-year term to be an adequate basis for rejecting the Settlement because the Commission will retain the authority during the term of the multiyear rate plan to investigate excessive rates and order them lowered.

D. Commission Action

The Commission finds that the August 16, 2016 Stipulation of Settlement will result in just and reasonable rates, is supported by substantial evidence, and that adopting it is in the public interest, and will therefore approve it. A number of factors, many of which have been touched upon in preceding sections of this order, inform the Commission's decision to approve the Settlement.

First, while the Settlement does not include all parties—the OAG's absence being the most notable—it is joined by a number of sophisticated parties representing a broad range of interests. The participation and unified support of this diverse set of parties, representing all classes of Xcel's ratepayers, affords significant assurance that the agreement they jointly reached will result in just and reasonable rates.

Compellingly, the Settlement is based on a smaller revenue requirement than that recommended by the Department—the one party charged with representing the general public interest. This gives the Commission great confidence that the Settlement will result in just and reasonable rates.

Second, the parties to this case—both settling and nonsettling—developed a robust evidentiary record by which to judge the Settlement. This record includes direct testimony on all revenue-requirement-related issues, rebuttal and surrebuttal testimony on issues disputed by nonsettling parties, extensive briefing, and an ALJ recommendation on all contested issues.

In particular, the record includes extensive evidence and findings on ROE. Although the ROE does not affect the Settlement’s revenue requirement, is important for Xcel in representing its financial health to the investment community and will allow the Commission to judge whether the Company’s earnings are reasonable over the four-year Settlement term. For the reasons discussed earlier, the Commission declines to modify the Settlement’s authorized ROE for purposes of riders or AFUDC calculations.

Third, the Settlement includes substantial ratepayer protections and other provisions that will provide rate stability and certainty over the four-year rate plan, while reducing the litigation burden on private and public intervenors. The Settlement sets forth maximum rate increases for each year, including a rate freeze in 2018; limits riders to those specifically identified; and ensures that Xcel will not seek another rate increase until 2020. And, as previously discussed, it includes a capital-projects true-up to ensure that ratepayers do not pay budgeted costs for capital projects unless those costs are actually incurred.

Fourth, the Settlement expressly recognizes the Commission’s authority under the multiyear-rate-plan statute to review and adjust the rates that result from the Settlement at any time during the four-year term.³⁷ And it obliges Xcel to continue to file annual reports “with its actual recorded jurisdictional financials and earnings to provide transparency in its financial performance.”

Finally, the rate increase resulting from the Settlement is in line with inflation and is consistent with the outcomes of prior Xcel rate cases. The following table shows the rate increases that were granted in Xcel’s last four rate cases as a percentage of the Company’s initial request in each case:

Docket No.	Request (\$ millions)	Increase (\$ millions)	Percent Approved
E-002/GR-08-1065	\$156.07	\$91.38	58.5%
E-002/GR-10-971	\$198.50	\$72.85	36.7%
E-002/GR-12-961	\$285.48	\$102.80	36.0%
E-002/GR-13-868	\$291.20	\$149.42	51.3%
Settlement	\$379.62	\$184.97	48.7%

The fact that the rate increase allowed by the Settlement—as a percentage of the Company’s initial request—is in line with those granted in prior, litigated cases is further evidence of its reasonableness.

For all these reasons, and based on its evaluation of contested issues in the preceding sections, the Commission will approve the August 16, 2016 Stipulation of Settlement in its entirety.

³⁷ See Minn. Stat. § 216B.16, subd. 19 (providing that, “[a]t any time prior to conclusion of a multiyear rate plan, the commission, upon its own motion or upon petition of any party, has the discretion to examine the reasonableness of the utility’s rates under the plan, and adjust rates as necessary”).

XVIII. Settled Issues – Housekeeping Items

A. Changes to In-service Dates – Mankato Energy Center II

Mankato Energy Center II (Mankato II) is a 345 MW gas-powered generator being built by Calpine Corporation in Mankato. Xcel has a power purchase agreement (PPA) with Mankato II that the Commission approved in February 2015.³⁸ The Company included Mankato II capacity-payment costs in its 2018 plan year; however, the generator's in-service date has since been extended to June 2019.

The Commission will require Xcel to make a compliance filing once the Mankato II in-service date becomes certain. If the in-service date does not materialize by 2019, the compliance filing should include the delay's 2019 revenue-requirement impact and how the Company proposes to address it.

B. Rate-Case Expense Amortization

Xcel proposed to amortize the anticipated \$3.34 million cost of this rate case over the term of the Settlement. Because most of the parties agreed to a settlement early in the proceeding, the final costs for the case are likely to be lower than initially projected. Accordingly, the Commission will require Xcel to make a compliance filing comparing final Rate Case Expenses to the requested \$3.34 million.

C. Sales-Forecast True-up

The 2016 sales-forecast true-up relied on weather-normalized sales data for all customer classes. Similarly, for the partially-decoupled classes, the true-ups in 2017–2019 will also be based on weather-normalized sales. To ascertain the impact of weather normalization on the true-up, the Commission will direct Xcel to include with its yearly true-up filing a true-up calculation based on actual, non-weather-normalized sales and revenue.

CLASS COST OF SERVICE STUDY ISSUES

XIX. Rate Design and Class Cost of Service Introduction

A. Rate Design and Customer Classification

The preceding section established Xcel's revenue requirement for the term of the multiyear rate plan. The following sections will address how Xcel may recover the revenue requirement from its ratepayers. This process of *rate design* requires the Commission to exercise policy judgment because there are many ways to set rates to enable a utility to recover appropriate revenues.

In designing rates, the Commission considers a variety of factors, including:

³⁸ See *In the Matter of Draft Purchase Power Agreements with Calpine Corporation and Invenergy Thermal Development, and Proposed Price Terms for Black Dog Unit 6*, Docket No. E-002/M-14-789, Order Approving Power Purchase Agreement with Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms with Xcel (February 5, 2015).

- Equity, justice, and reasonableness, and avoidance of discrimination, unreasonable preference, and unreasonable prejudice;³⁹
- Continuity with prior rates to avoid rate shock;
- Revenue stability;
- Economic efficiency;
- Encouragement of energy conservation;⁴⁰
- Customers' ability to pay;⁴¹
- Ease of understanding and administration; and, in particular,
- Cost of service.

Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different customers, and will incur many costs that benefit multiple customers. Because similar types of customers tend to impose similar types of costs on the system, utilities simplify their analysis by first dividing customers into classes—for example, distinguishing residential customers from commercial or industrial customers. Utilities then attempt to determine the amount of revenues they should recover from each customer class.

To aid this analysis, the Commission directs utilities to conduct a class-cost-of-service study (CCOSS). Minn. R. 7825.4300(C) directs a utility to file

A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations.

B. Class-Cost-of-Service Studies

According to the *Electric Utility Cost Allocation Manual* of the National Association of Regulatory Utility Commissioners (NARUC Manual), performing a CCOSS involves three steps. First, costs are grouped according to their function (generation/production, transmission, distribution, customer service/facilities, administrative). Second, costs are classified based on how they are incurred. Third, costs are allocated to the various customer classes.⁴²

Functionalization: In this case, the two functions that generated the most dispute are generation and distribution.

Generation refers to the cost of plant used to generate electricity.

³⁹ Minn. Stat. §§ 216B.01, .03.

⁴⁰ Minn. Stat. §§ 216B.03, .2401, 216C.05.

⁴¹ Minn. Stat. § 216B.16, subd. 15.

⁴² *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, at 18–23 (January 1992).

The distribution system carries electricity from the transmission system to a customer's location. Utilities distinguish between the primary distribution system and the secondary distribution system. In the primary distribution system, electricity travels from the high-voltage transmission system to substations, which reduce the voltage and distribute it via lines and poles to the neighborhoods of retail customers. While some large industrial customers purchase power at primary distribution voltages, generally this electricity flows to the secondary distribution system, where distribution transformers again reduce the voltage, permitting it to be distributed via lines and poles to customer premises.

Classification: The cost of a function might be classified as related to *energy, demand, or customers*. Energy-related costs increase as customers' consumption of energy increases. Demand-related costs increase as the rate at which customers consume energy increases, especially during periods of peak demand. Customer-related costs increase as the number of customer accounts increases. According to the NARUC Manual, the cost of an electric utility's distribution system is related to energy, demand, and customers.

Allocation: The various costs then get allocated to each customer class. For purposes of its CCOSS, Xcel divides its customers into four classes:

- Residential
- Commercial, without Demand Meters (Non-Demand)
- Commercial & Industrial, with Demand Meters (Demand)
- Street & Outdoor Lighting

For commercial and industrial customers with a demand meter, Xcel calculates a charge for the cost of the facilities required to serve that customer's peak usage (a "demand charge"), as well as a separate charge for the amount of energy consumed. For customers in the other customer classes, the costs of energy and demand are recovered through a per-kWh charge.

The manner in which a CCOSS characterizes costs influences how the study will assign responsibility for raising revenues among the customer classes. For example, because the great majority of Xcel's customers are residential customers, a choice to characterize a cost as a customer cost will result in residential customers bearing the great majority of those costs.

C. Multiyear Rate Case

Because Xcel filed a multiyear rate case, its CCOSS calculated a new estimate of costs attributable to each customer class for 2016, 2017, and 2018.

XX. CCOSS—Classifying Fixed Production Plant

A. Introduction

As noted above, cost classification requires a utility to determine whether a cost varies as the number of customers increases, or as the amount of energy consumed increases, or as the maximum rate of consumption increases. No party disputes that the cost Xcel bears for production plant is driven by the level of demand for electricity; Xcel designs its system to be able to meet the anticipated peak level of demand, and maintain a specified amount of additional generating capacity (known as a reserve margin) to address unanticipated levels of demand or

equipment failures. But parties disagree about the extent to which production-plant costs also reflect energy costs.

B. Positions of the Parties

The Chamber proposed classifying production plant costs using the Peak Responsibility Method. The Chamber reasoned that Xcel's investment in production plant is a fixed cost that cannot vary based on how much energy customers consume. Only variable costs, such as the cost of fuel, should be classified based on energy consumption, the Chamber argued; the fixed costs should be classified as demand costs, to be allocated to customer classes in proportion to each class's consumption during the period of peak demand.

In support of its argument, the Chamber noted that its Peak Responsibility Method for classifying fixed production plant is included in the NARUC Manual. Even if the Commission were not inclined to rely solely on this method, the Chamber argued that it should consider this method along with any other method the Commission chooses.

In contrast, Xcel proposed using its Stratification Method, a variant of the Equivalent Peaker Method set forth in the NARUC Manual, which Xcel has employed since the 1970s. Xcel acknowledged that it selected its portfolio of generators to meet its anticipated peak demand and reserve margins. But Xcel observed that if it were to design a system solely to serve that function, it might have built its entire system out of natural gas "peaking" generators, which have the lowest capital cost per unit of generation. Yet these generators also have high operating costs per unit of energy generated. According to Xcel, the fact that it (and other electric utilities) chose to rely on a variety of generators—including generators with higher capital and lower operating costs—demonstrates that utilities design their systems based on factors beyond meeting peak demand.

Because some share of the capital costs are incurred not to acquire additional generating capacity, but to reduce energy costs, Xcel argued that this share of capital cost should be treated as energy-related costs. Xcel's Stratification Method includes a formula for determining the appropriate share of capital costs to regard as energy costs.

Xcel did not support adopting multiple classification methods, but conceded that the rationale for adopting multiple methods for distribution plant would also support adopting multiple classification methods for fixed production plant.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge noted that the Commission has consistently approved the Stratification method for classifying fixed production plant, and that the matter was sufficiently well established that no party chose to file direct testimony supporting any other theory. The Chamber filed its alternative proposal only in surrebuttal testimony when no party would have the opportunity to file responsive testimony. Because the Chamber's proposal was insufficiently developed in the record, the Administrative Law Judge recommended that the Commission reject it.

D. Commission Action

The Commission concurs with the Administrative Law Judge. The Commission has long recognized that the cost Xcel incurs for its fixed production plant is driven not only by the need to meet peak demand, but also by the need to manage energy costs (including environmental costs). Even the Chamber acknowledged this fact.

The Chamber's proposal, whatever its merits, arose too late in the proceedings to justify consideration here. Consequently the Commission will continue its reliance on the Stratification Method.

XXI. CCOSS—Classifying Distribution Plant

A. Introduction

Parties disagreed about the most appropriate method for classifying the cost of distribution plant.

According to the NARUC Manual, the cost of an electric utility's distribution system is related to energy, demand, and customers.⁴³ Yet the two methods that the Manual identifies for allocating such costs—the Minimum System Method and the Zero Intercept Method, discussed below—classify the cost of distribution plant as related to demand and customers, and do not classify any part of the distribution system as related to energy.

B. Positions of the Parties

Parties proposed six different methods for classifying distribution costs. Xcel employed the *Minimum System Method* and a variant, the *Zero Intercept Method*, and later combined them to form its *Hybrid Method*. The OAG employed the *Basic Customer Method* and the *Peak-and-Average Method*. Finally, the Chamber proposed relying in part on the *Customer-Related Method*.

1. The Minimum System Method

First, Xcel classified its distribution plant costs using the Minimum System Method. This method reflects the premise that distribution costs should be divided between customer-related costs and demand-related costs, because a utility builds out its distribution plant in order to (a) serve each customer regardless of the amount of demand that each customer puts on the system, and (b) have sufficient capacity to reliably meet customers' peak demand. To use this method, an analyst estimates the cost to build a system that could provide each of Xcel's customers with some minimal level of service. The cost of this minimum system would reflect customer-related costs; any additional costs would be assumed to relate to the need to build capacity to deliver more than just a minimal level of service—that is, demand-related costs.

The Chamber, the Commercial Group, the Department, and XLI generally found this classification method to be reasonable. However, the Department argued that Xcel could improve upon this CCOSS by incorporating data from additional years, and by adjusting its booked cost data to account for inflation.

⁴³ NARUC Manual, at 21–22.

The CEO and the OAG criticized Xcel's reliance on this classification method. First, they questioned the choice to divide distribution costs between demand-related costs and customer-related costs, without considering other possibilities such as energy-related costs. For example, the OAG argued that Xcel incurs certain distribution costs for the purpose of reducing energy losses, and that such costs should be regarded as energy-related. The CEO and OAG argued that this foundational defect in Xcel's CCOSS led to results that exaggerate the customer-related costs for distribution plant. The CEO went further, arguing that this initial bias supported mistaken conclusions about the minimum cost to serve a customer, and thus would inflate the costs that Xcel would eventually propose to be borne by low-usage residential customers.

The OAG raised additional concerns about Xcel's proposal. Generally, the OAG argued that the cost of some minimally sized system reaching all customers would reflect more than just the number of customers: it would also reflect customer density, terrain, reliability and quality standards, and other factors. The OAG argued that Xcel's Minimum System Method analysis relied on a variety of arbitrary or questionable assumptions. And the OAG also questioned whether the cost data reflected booked costs, installed costs, or current costs. The net effect of these errors, the OAG alleged, was to generate estimates that exaggerated customer-related costs.

2. The Zero Intercept Method

Second, Xcel classified its distribution plant costs using the Zero Intercept Method. This method also calculates customer-related costs based on the cost of a minimum distribution system. But while the Minimum System Method calculates customer costs in a manner that reflects some level of service capacity—that is, some demand-related costs—the Zero Intercept Method does not. Instead, recognizing that the cost of distribution plant increases as its capacity increases, the Zero Intercept Method uses a mathematical model to project this pattern backwards to estimate the cost of a hypothetical distribution system that would have precisely zero capacity.

Again the Chamber, the Department, and XLI generally found this classification method to be reasonable, and again the Department proposed technical changes for future CCOSSs. The Department found one instance in which Xcel's analysis (regarding underground transformers) may have violated the requirements of the underlying mathematical model, but this did not alter the Department's support for the method.

Again, the CEO and the OAG disputed the merits of classifying costs into demand-related costs and customer-related costs, without considering energy-related costs. In addition, the OAG argued that Xcel's Zero Intercept Method analysis relied on biased data, and insufficient data to support the results of the method's mathematical model.

3. The Hybrid Method

Ultimately Xcel did not recommend that the Commission adopt either its Minimum System Method or its Zero Intercept Method to classify distribution costs. Instead, Xcel proposed incorporating the two into a third method, its Hybrid Method. Xcel divided its distribution plant into functional categories, and then used the previous two classification methods to estimate the share of customer-related costs in each category. Where these two methods disagreed, Xcel would pick the smaller of the two estimates of customer-related cost. The remaining share of costs in each category would be assumed to be demand-related costs.

In support of this choice, Xcel argued that both the Minimum System Method and the Zero Intercept Method were designed to identify the cost of some minimally sized distribution plant necessary to reach all customers, and to characterize only that cost as customer-related. Xcel found both models reasonable, and reasoned that by picking the lowest allocation attributed to customer costs, Xcel could best fulfill the models' objectives.

Again the Chamber and the Department generally found this classification method to be reasonable, and again the Department proposed technical changes for future CCOSSs. But while XLI supported both the Minimum System and Zero Intercept Methods, it opposed the Hybrid Method. XLI argued that the Hybrid Method, by picking data from the other two methods based solely on the criterion of minimizing customer costs, was structurally biased to inflate demand costs—which would ultimately have the effect of increasing rates for the Commercial & Industrial Demand class and the Lighting class.

Because the Hybrid Method incorporates both of the previous two methods, the CEOs' and the OAG's objections to those earlier methods also applied to the Hybrid Method. Acknowledging that all classification methods are imperfect, however, the OAG did not ask the Commission to reject this method entirely. Instead, the OAG asked the Commission to consider this method along with two other classification formulas: the Basic Customer Method and the Peak-and-Average Method, discussed below. In support of its position, the OAG cited prior Commission decisions directing utilities to consider multiple CCOSS models.

4. The Basic Customer Method

Similar to the previously discussed classification methods, the Basic Customer Method begins by attempting to identify the subpart of distribution costs that should be characterized as customer-related costs, and assumes that any excess cost should be attributed to demand. But while the Minimum System Method calculates customer-related costs based on the cost of a minimum distribution system, the Basic Customer Method includes only costs that can be attributed to individual customers—such as the costs of meters, billing, and collection—and treats the remaining shared costs as related to demand. Compared to the Minimum System Method, the Basic Customer Method classifies less cost as customer-related, and more cost as demand-related.

In support of the Basic Customer Method, the OAG reasoned that distribution plant that serves more than one customer is shared plant, and that Xcel designed its distribution system to have sufficient capacity to maintain service during periods of peak demand, rendering most of these shared costs demand-related costs. The OAG also cited academic studies and decisions from other jurisdictions supporting the use of the Basic Customer Method.

The Chamber, the Department, Xcel, and XLI opposed the Basic Customer Method, arguing that this formula would fail to classify costs based on cost causation and would be inconsistent with many prior Commission orders. The Chamber expressed concern that this method would allocate excessive costs to Xcel's commercial and industrial customers, making their operations uncompetitive with firms operating in an environment with cheaper electricity.

5. The Peak-and-Average Method

The previously discussed classification methods anticipate that demand-related costs will be allocated among customer classes based on each class's share of energy consumption during the period of peak demand. These methods reflect the idea that a utility designs and builds its system to have sufficient capacity to meet the needs of all its firm customers during periods of peak

demand, no matter how brief that period is. In practice, this dynamic causes residential consumers to bear a share of the utility's costs that is larger than the share of energy that residential customers consume.

In contrast, the Peak-and-Average Method proposes to support a cost allocation that reflects not only usage during the rare peak periods, but also usage during the average periods. Similar to the Basic Customer Method, this method identifies a narrow range of customer-specific costs—generally, the cost of customer meters and service drop lines—and identifies a share of the remainder as demand-related costs to be allocated based on each customer class's energy consumption during periods of peak demand. But the Peak-and-Average Method also identifies a share of costs to be allocated based on each class's average demand—in effect, based on the class's share of total energy consumed. This has the effect of assigning less distribution-system cost to residential customers, and more to industrial customers.

In support of its proposal, the OAG noted that the NARUC Manual includes the Peak-and-Average Method among its approved classification methods—although the manual approves this method for classifying production costs, not distribution costs.

The Chamber, the Department, Xcel, and XLI reiterated the objections that they raised with regard to the Basic Customer Method, emphasizing their claim that this method fails to classify cost based on cost causation. They argued that Xcel must build its distribution plant to reliably serve customers during periods of peak demand—making these costs demand-related costs. Because Xcel incurs little additional distribution-plant cost to serve customers during average periods, these parties disputed the merits of classifying costs on this basis. Xcel reported that it could not identify any jurisdiction that had adopted this method for allocating distribution plant.

6. The Customer-Related Method

Finally, if the Commission adopts any or all of the OAG's CCOSS methods, the Chamber would ask the Commission to also adopt its Customer-Related Method. This method reflects the premise that the cost of Xcel's distribution plant increases as the number of Xcel's customers increases, and thus would allocate distribution costs among customer classes in proportion to the number of customers in each class. This method would allocate more costs to the residential class than any other allocation method in the record.

The OAG opposed this method, arguing that it lacked any plausible relationship to cost causation.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Minimum System Method, the Zero Intercept Method, and the Basic Customer Method were imperfect but reasonable means for allocating the cost of the distribution plant. But because Xcel's Hybrid Method would act to mitigate the imperfections in the Minimum System and Zero Intercept methods, the ALJ found that method to be the most reasonable allocation method in the record.

The ALJ noted that the NARUC Manual, in setting forth allocation methods for distribution plant, discusses only the Minimum System and Zero Intercept methods. The Commission has long favored using one or both of these methods for allocating distribution costs—as have the regulatory commissions in neighboring states. Moreover, the Commission has refined Xcel’s CCOSS over the years to make it more transparent. The ALJ found that the parties who filed testimony on CCOSS all conceded the merits of the Minimum System Method or Zero Intercept Method or both.

The ALJ acknowledged that the Basic Customer Method had the advantage of simplicity, but found that this method inappropriately characterized certain customer-related costs as demand-related.

The ALJ noted that XLI argued that Xcel’s Hybrid Method reflected an undue bias in favor of lower cost for residential customers. But the ALJ concluded that the Hybrid Method was designed to guard against overstating customer costs, and so Xcel was justified in taking such precautions.

The ALJ rejected the Customer Related Method (with its emphasis on customer-related costs) and the Peak-and-Average Method (with its emphasis on energy-related costs) for failing to give sufficient weight to the fact that electric utilities design their systems to meet peak demand. The ALJ concluded that these two methods generated extreme—and generally offsetting—allocation results.

The ALJ gave special attention to the role of energy-related costs in the distribution system. The NARUC Manual makes passing reference to distribution plant reflecting energy-related costs, but also explicitly denies that distribution plant reflects energy-related costs. In any event, the only allocation methods listed in the manual for distribution plant divide the costs into two categories—customer-related costs and demand-related costs—with no component characterized as energy-related. While the OAG argued that utilities design their distribution systems to reduce the amount of energy lost, the record reveals that line losses in the distribution system are less than eight percent. The ALJ found that this fact undermined the credibility of the Peak-and-Average Method, which characterizes most distribution costs as energy-related.

D. Commission Action

While the parties have rigorously argued and disputed the best method for allocating distribution costs, they all concurred with the ALJ in this: Cost models are imperfect. They build a simplified model of a utility’s system, and use the model to draw conclusions allocating costs into functional categories to help inform the Commission’s eventual allocation of joint costs among customer classes.

Thus, for example, the OAG correctly observed that the cost to serve a population of customers will vary depending not only on the number of customers, but on their dispersion, the terrain in which they live, and many other variables. Nevertheless, when a utility serves a large population, it is not unreasonable to expect a cost model to identify costs that correlate with the number of customers served, and the average magnitude of those costs per customer. Because the Commission will ultimately establish uniform rates within each customer class—rates that will not vary based on the type of terrain surrounding a customer’s premises, for example—adding this level of precision to a cost model may cause burdens without any corresponding benefits.

Xcel and the Department recommended that the Commission rely on Xcel’s Hybrid Method, which is a combination of two other methods. Similarly, the OAG urged the Commission to consider still other allocation methods. And the ALJ acknowledged that the Commission may wish to give credence to multiple methods, noting that Xcel’s Hybrid Method may understate demand-related costs while the Basic Customer Method would overstate these costs. All of this

is consistent with the NARUC Manual's conclusion that no single cost-study method can be judged superior to all others in all contexts. For these reasons, the Commission will consider a range of classification methods for purposes of allocating responsibility for the necessary revenues among Xcel's various customer classes.

Anticipating this outcome, the ALJ recommended that the Commission state how much weight it would give to the results of each functionalization method in Xcel's next rate case. But one term of Xcel's settlement in this proceeding is that Xcel would refrain from seeking a general rate increase for the next four years. The Commission is disinclined to impose this degree of precision on the kind of cost study Xcel may find appropriate four years hence. It will suffice to say that by providing multiple methods for functionalizing costs, parties provide a range of guidance upon which the Commission may rely in allocating costs among Xcel's customer classes.

XXII. CCOSS—Calculation of D10S Allocator

A. Introduction

As previously discussed, a CCOSS classifies certain investments as related to demand. No party disputed that these investments would be allocated among the customer classes in proportion to each class's energy consumption during periods of peak demand. But parties disagreed about what constitutes the relevant period of peak demand.

Historically electric utilities operated independently, building their own plant to generate, transmit, and distribute electricity to their own customers. These utilities designed their system to be able to meet their customers' needs during periods of peak demand, plus maintain a margin of capacity to manage unanticipated circumstances (extra demand, or unplanned outages from a generator or transmission line).

But today many electric utilities join together to form independent system operators such as MISO. Through MISO's wholesale energy markets, utilities benefit from the use of each other's facilities. This does not mean that utilities no longer need to make arrangements to serve their peak load, or to maintain a reserve margin. But a utility may anticipate relying on the regional power system to help meet the utility's needs.

MISO establishes the required amount of reserve capacity, and allocates the responsibility for meeting this obligation among load-serving entities such as electric utilities. Finally, MISO calculates this reserve margin based on peak demand for the relevant MISO Zone—which may not coincide with the peak demand on any individual utility's network.

For Xcel, these two peak demands do not coincide. The 2016 period of peak demand for MISO Local Resource Zone 1 (which includes Xcel's service area in Minnesota) occurred on July 14 at 3:00 p.m.⁴⁴ But the 2016 period of peak demand for Xcel's system occurred two weeks later, on July 28 at 4:00 p.m. More significant than the difference in time is the difference in usage patterns during the two peaks. Specifically, during the MISO peak, commercial and industrial customers were consuming a larger share of total energy than during the Xcel peak, while

⁴⁴ The MISO Peak D10S Allocator is based on the hour of highest demand in MISO's Local Resource Zone-1, which encompasses most of Minnesota, all of North Dakota, and portions of Montana, South Dakota, and Wisconsin. See <http://www.misomtep.org/independent-local-forecasting/>.

residential customers followed the opposite pattern. Thus, the choice between methods for measuring demand will have foreseeable consequences for different customer classes.

B. Positions of the Parties

In compliance with a Commission directive from Xcel's last rate case, Xcel calculated its measure of demand—which Xcel labels the *D10S Allocator*—for both a MISO peak and an Xcel peak.

Xcel initially favored reliance on the MISO Zonal peak for purposes of allocating demand-related costs among customer classes. But after considering the positions of the Chamber, the Department, the ICI Group, and XLI, Xcel switched its position and began arguing for using its own system peak as the measure for D10S.

Xcel argued that it designs its system to meet the peak demand that its customers impose on Xcel's system. In contrast, Xcel argued that a D10S Allocator developed on the basis of MISO's Zonal peak hour would not accurately reflect the factors that cause Xcel to incur additional capacity costs.

The Chamber, the Department, the ICI Group, and XLI supported Xcel's position.

In contrast, the OAG supported using the MISO system peak. The OAG reasoned that Xcel must have extra generation available to provide the capacity reserve margin that MISO mandates. The OAG argued that many of the primary decisions that drive Xcel's resource planning—and, therefore, cost causation—are made at the MISO level.

C. The Recommendation of the Administrative Law Judge

The ALJ concurred with Xcel. The ALJ found that Xcel designs its plant to meet the peak demand of its own customers on its own system, and therefore Xcel's D10S Allocator should reflect this fact. The ALJ also expressed concern about the variability in the D10S allocator based on MISO's Zonal peak.

D. Commission Action

At one time, Xcel's primary focus for system design was doubtless on the peak demand for its system. But now that Xcel is a member of MISO, Xcel must meet the reserve requirements established by that organization.

While Xcel and other parties persuaded the ALJ that Xcel designs its system to meet its own system peak, the Commission notes that MISO prescribes the formula for calculating the amount of capacity that any given member is to maintain. And those reserve requirements are designed to meet the peak load of the MISO Zone. While calculating the D10S Allocator on the basis of the MISO Zonal peak may generate allocations that change over time, the same is true of an allocator based on Xcel's own system peak.

Prospectively, therefore, the Commission will direct Xcel to base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak. And given that MISO is expecting to change its own formula for allocating costs during peak demand, the Commission will also direct Xcel to incorporate into its next rate case any changes that MISO adopts.

XXIII. CCOSS—D60Sub Capacity Allocator

A. Introduction

In electricity transmission and distribution, substations provide a means for converting high-voltage electrical current to low-voltage current, and vice versa. While most substations serve the transmission/distribution grid as a whole, a utility may build a substation purely to serve one or more large industrial consumers.

Xcel uses its D60Sub Capacity Allocator to recover the cost of substations from among all its customers—unless those substations serve a specific customer. In that case, those costs are directly assigned to the specific customer.⁴⁵

But if a large industrial customer is already bearing the directly assigned costs of its own substation or substations, should that customer also have to bear a share of the cost of the other substations? The parties disagreed.

B. Positions of the Parties

According to the Department, all customers benefit from the transmission and distribution systems, which includes substations, and so all customers should bear a share of these substation costs. The fact that a customer bears the directly assigned cost of one or more substations should not excuse that customer from also bearing a fair share of the allocated costs, the Department argued.

Xcel, the OAG, and XLI disagreed. They acknowledged that all customers should bear a portion of the cost of, say, the transmission system. But where a customer is served from a designated substation—and already bears the cost of that substation—these parties agreed that it would not be appropriate to ask that customer to also bear a share of the cost of substations that do not serve the customer.

C. The Recommendation of the Administrative Law Judge

The ALJ agreed with the majority of parties that a customer who receives service via a specific substation, and bears the direct cost of that substation, need not bear the additional cost of substations from which the customer derives no benefit.

D. Commission Action

The Commission concurs: If a party is directly assigned the cost of a substation, and receives service via that substation to the exclusion of all the other substations, then the party should be excused from bearing a share of the cost of the substations that do not serve the customer. The Commission will direct Xcel to incorporate this change into its CCOSSs in future rate cases.

⁴⁵ *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minn. Gas and Electric Utilities*, Docket No. G,E-99/CI-90-1008, Order Setting Filing Requirements (September 28, 1994) at 4-6, as modified by Order Clarifying Commission Order Dated September 28, 1994 (March 7, 1995) (collectively, Cost Allocation Order).

XXIV. CCOSS—Allocation of the Cost of Stranded Facilities

A. Introduction

Where Xcel builds a facility for the benefit of a member of the Commercial & Industrial class, it directly assigns to that customer the cost of that facility. But when the customer ceases to take service from Xcel, should Xcel allocate the cost to the other members of the Commercial and Industrial class? Or should the costs be shared among all customer classes, as just one more general cost that utility incurs? The parties disagreed on how to resolve this issue.

B. Positions of the Parties

The Department cites the Commission's Cost Allocation Order for the proposition that, where a cost cannot be directly assigned, it becomes a common cost to be allocated based on an analysis of the cost's origins or, barring that, based on a similar cost category.⁴⁶ The Department reasons that, barring an opportunity to recover the cost of an asset from the Commercial/Industrial customer who directly caused Xcel to incur the cost, the second-best proposal is to recover the costs from the same customer class. But the Department acknowledged that if a facility could be repurposed, an appropriate share of the facility's cost should be allocated in accordance with the new purpose.

According to XLI, the cost of a stranded facility is simply a cost of doing business for a regulated utility. XLI argued that there was no more reason to assign the cost of one Commercial & Industrial customer to other Commercial & Industrial customers than to Residential or Lighting customers.

Xcel concurred with XLI.

C. The Recommendation of the Administrative Law Judge

The ALJ was persuaded by the Department that the Commission's prior findings regarding cost allocation govern this question, and that costs that originated within a Commercial & Industrial class should be recovered from that class.

D. Commission Action

The Commission concurs. As the Commission's Cost Allocation Order illustrates, cost recovery is an inexact science. As noted in the Commission's Cost Allocation Order, the Commission favors assigning costs directly where possible, assigning costs indirectly where not, and treating expenditures as general overhead costs as a last resort.⁴⁷

Here, Xcel has built facilities to serve specific Commercial & Industrial customers, some of whom no longer take service from Xcel. These costs were caused by the customers requesting the facilities—but also by Xcel's policy of accommodating certain kinds of requests from large customers. This policy arguably benefits the Commercial & Industrial classes generally—and the costs of the policy should accrue to those who benefit most proximately.

⁴⁶ Cost Allocation Order, at 4–6.

⁴⁷ *Id.*

XXV. CCOSS—Allocation of Line Losses

A. Introduction

The amount of electricity Xcel generates exceeds the amount it delivers to retail customers because some amount of energy is lost through the process of transmission and distribution. Line loss is an inevitable cost of operating an electric utility, and Xcel recovers that cost from ratepayers generally.

But arguably Xcel incurs more of these costs in serving some customers than others. This is because line losses do not occur uniformly; certain factors lead to higher line losses—and these factors are arguably associated with serving the Residential class.

For example, line losses increase as voltage decreases. Thus, a single large industrial customer may buy as many kWh as a neighborhood of residential customers—but if the large customer receives the electricity at a higher voltage, Xcel will incur less line loss in delivering those kWhs than when delivering the same total energy to residential customers at a lower voltage.

Also, line losses increase during periods of peak demand, as lines become hot and congested. Large commercial and industrial customers tend to consume energy at a more uniform rate over time; lighting customers consume energy off-peak; but residential customers tend to consume a disproportionate share of energy during peak hours. Thus it is plausible that Xcel incurs a disproportionate share of its line losses serving residential customers.

The parties disagree about whether Xcel must incorporate these dynamics into its CCOSS.

B. Positions of the Parties

XLI argued that principles of cost causation should compel Xcel to incorporate line-loss dynamics into its CCOSS. Otherwise, the Commercial & Industrial classes would subsidize other customer classes—especially the Residential class.

Both Xcel and the Department stated that they were willing to consider the idea, but found that it was unclear whether Xcel had the necessary data to conduct the relevant analyses. The Department noted the possibility that the cost of adding this level of precision might exceed its benefits. But Xcel expressed a willingness to explore the issue in its next rate case.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that XLI's proposal was theoretically sound, uncontested, and worthy of consideration—in Xcel's next rate case. Thus the ALJ recommended that the Commission direct Xcel to report on methods to conduct line-loss studies to develop a more accurate measure of line losses in the future. The ALJ specifically proposed that Xcel treat line losses as an energy-related cost.

D. Commission Action

The Commission concurs with the parties that consideration of line losses may further enhance the accuracy of CCOSSs. As a result, the Commission will adopt the ALJ's recommendation to direct Xcel to report on methods to conduct loss studies to measure these losses.

That said, at this early stage the Commission will decline to constrain Xcel's choice to treat line losses as energy-related, demand-related, both, or neither. The design of the studies will be a matter for all participants to explore together.

XXVI. CCOSS—Allocation of the Cost of the Renewable Development Fund

A. Introduction

The Minnesota Legislature created the Renewable Development Fund (RDF) by statute to promote renewable electric energy resources and projects and to assist companies in the renewable electric energy industry.⁴⁸ The statute directs the owner of the Prairie Island and Monticello nuclear generating plants—that is, Xcel—to finance the fund based on the number of dry casks containing spent fuel that Xcel stores by the plants.

Parties disagreed about the appropriate means to allocate the cost of fund contributions and administration among Xcel's customer classes.

B. Positions of the Parties

The Chamber objected to Xcel's practice of allocating RDF costs to classes in proportion to each class's energy consumption. Concluding that research and development was no more likely to be energy-related than demand-related, the Chamber proposed allocating only half of these costs based on each class's cost-weighted energy consumption (the E8760 Allocator), and half based on demand (the D10S Allocator).

The OAG argued that the Chamber's proposal, whatever its merits, would not create more than a 0.01 percent change in cost allocations to the Commercial & Industrial Demand class. On this basis, the OAG recommended foregoing this change.

The Department and Xcel also opposed the Chamber's proposal on the grounds that the matter could be more appropriately addressed in any of Xcel's regular dockets specifically addressing the RDF. The Chamber found this proposal acceptable.

C. The Recommendation of the Administrative Law Judge

The ALJ rejected the Chamber's proposal for lacking sufficient foundation in the record. The ALJ concluded that Xcel's RDF costs were neither energy-related nor demand-related, but were Legislature-related; accordingly, the ALJ could find no merit in the Chamber's proposal.

D. Commission Action

Because the matter raised by the Chamber has been insufficiently developed, the Commission will decline to render a decision one way or another, other than to concur with the consensus that this matter need not be addressed in this docket.

Likewise, the Commission will decline to expressly assign this issue to Xcel's next RDF Rider docket. Interested parties should feel free to raise this matter on their own initiative, if they wish.

⁴⁸ Minn. Stat. § 116C.779

XXVII. CCOSS—Allocation of the Cost of Conservation Improvement Programs

A. Introduction

The Legislature has also created the Conservation Improvement Program (CIP). CIP encompasses most of the state's energy-conservation and energy-efficiency initiatives, from energy audits and appliance rebates to energy-efficient construction guidelines and manufacturing process improvements. CIP costs are recovered through the Conservation Cost Recovery Charge (CCRC) and the CIP Rider. The CCRC is recovered via a utility's base rates, while CIP Rider costs are recovered via a per-kWh charge that is included in the Resource Adjustment on customers' bills.

Approximately \$89 million of CIP costs are recovered through base rates and \$40 million through the rider. The usage of CIP-exempt customers (certain commercial and industrial customers) is excluded from the allocator.

Parties disagreed about whether to allocate these costs based on simple energy sales, or based on cost-weighted energy sales (the E8760 Allocator).

B. Positions of the Parties

Xcel allocated both the CCRC and the CIP Adjustment Factor (CAF) on the basis of energy consumption. Specifically, CCRC costs were allocated to customer classes using the 2016 test-year sales forecast after subtracting sales to CIP-exempt customers.

The Chamber proposed that the CIP CCRC costs be allocated using the percent-of-benefits method. The percent-of-benefits method is intended to reflect the cost allocations that would result from the supply-side investments that CIP expenditures permit a utility to forgo.

As an alternative, the Chamber suggested that if the Commission intends to allocate conservation costs based on energy sales, the Commission should adopt the E8760 Allocator that excludes CIP-exempt customers. Because the E8760 Allocator links hourly marginal prices to hourly customer loads, the Chamber argued, it provides a more accurate pricing signal for CIP-related initiatives. The Chamber showed that using the E8760 Allocator after excluding CIP-exempt customers resulted in shifting costs away from the Street Lighting and C&I Demand class and onto the Residential and C&I Non-Demand classes.

The OAG opposed changing the allocator, arguing that the goal of CIP was to reduce kWh sales, not marginal energy costs.

But Xcel, the Chamber, the Department, and XLI all supported the idea of evaluating the use of the E8760 Allocator, with CIP-exempt usage excluded, in Xcel's next CIP Rider proceeding.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the record provided insufficient information about the Chamber's proposal, and the Legislature's goals for CIP, to justify adopting it. The ALJ suggested that parties might choose to take up this matter in a CIP rider docket.

D. Commission Action

As with the Chamber's proposal for changing how CCOSSs deal with the Renewable Development Fund, the Commission finds that the proposal for changing how CCOSSs allocate CIP expenditures is insufficiently developed. As the OAG observed, it is far from clear that CIP costs should be allocated based on the E8760 Allocator rather than simply based on energy sales.

Again, while the Commission will decline to refer this matter to Xcel's next CIP Rider docket, interested parties should feel free to raise this matter on their own initiative, as they wish.

XXVIII. CCOSS—Allocation of the Cost of Solar Power Purchase Agreements

A. Introduction

Presently, power purchase agreements (PPAs) for electricity generated by the sun are recovered through the fuel clause adjustment (FCA) using the E8760 allocator; all these costs are characterized as energy-related.

Yet MISO recognizes that solar generators provide not only energy, but also generating capacity. This is because solar generators generate fairly reliably during periods of peak demand, which typically occur in the afternoon. Specifically, MISO has a default assumption that solar-powered generators have an accredited capacity of half of their nameplate level of generation (recognizing that solar energy is somewhat reliable, but not as reliable as dispatchable sources of generation such as fossil-fuel-powered generators).

Parties disagreed about whether some portion of the cost of solar PPAs should be characterized as demand-related, and allocated according to the D10S Allocator.

B. Positions of the Parties

The Chamber argued that only half of the cost of a solar PPA should be allocated based on energy, and the other half should be allocated based on demand (the D10S Allocator).

The Department found the Chamber's proposal to be reasonable for recovering the cost of solar PPAs that have been embedded in base rates.

But Xcel and the OAG opposed the Chamber's proposal. The OAG argued that the record did not support changing the Commission's long-standing treatment of solar PPAs as energy-related, and the long-standing practice of allocating the costs based on the E8760 allocator.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission not rely on MISO's default policy of crediting half of a solar generator's nameplate generating capacity, on the theory that the dynamics that apply to MISO's system are not the same as the dynamics that apply to Xcel's system. This echoed the ALJ's reasoning leading to the conclusion that Xcel should calculate its D10S Allocator based on Xcel's system peak, not the MISO Zone's peak.

The ALJ emphasized that this recommendation reflected the current state of the record, and that a different decision might be warranted in a future proceeding.

D. Commission Action

Again, the Commission is not persuaded of the need to continue calculating Xcel's D10S Allocator based on Xcel's system peak, without regard to MISO's peak. But the Commission concurs that the merits of re-allocating the cost of solar PPAs have received insufficient attention in this proceeding to warrant adoption. For this reason, the Commission will adopt the ALJ's recommendation and decline to direct Xcel to make this change in future CCOSSs.

RATE DESIGN ISSUES

XXIX. Interclass Revenue Apportionment

A. Introduction

As previously noted, after the Commission establishes a utility's revenue requirement, the Commission must design rates that will provide the utility with a reasonable opportunity to recover these costs. The next step in that process is to establish the share of Xcel's revenue requirement to be recovered from each class of customers served by the utility. In making this apportionment, the Commission considers the totality of the evidence in the record, and especially the costs that the utility incurs to serve each customer class (as established by CCOSSs).

B. Positions of the Parties

Generally, each party identified its favored CCOSS or CCOSSs, discussed above, and recommended apportioning responsibility for Xcel's revenue requirement in a manner that would cause each customer class to approach bearing the full costs indicated by the favored CCOSS. Because Xcel has proposed a multiyear rate plan, parties had the opportunity to propose implementing shifts to the revenue apportionment gradually over four years to mitigate the risk of rate shock. The parties differed in their choice of CCOSS, and in the speed with which rates should transition to achieve the apportionments specified in the CCOSSs.

1. Xcel

Xcel proposed to gradually phase in changes to its interclass apportionments to cause each class to fully bear the costs assigned to it by the Hybrid Model CCOSS by 2019.

Generally Xcel would implement two-thirds of this change by 2017, hold the apportionments uniform for 2018, and transition all the way to cost-based apportionment by 2019. But because Xcel's CCOSS proposes a relatively large increase to the Lighting class, Xcel would propose to limit the increases to this class to no more than ten percent in any given year. As a result, by 2017 the gap between the costs attributed to the Lighting Class and the revenues recovered by that class would decrease by only half, rather than two-thirds.

2. The Commercial Group, XLI, and the Chamber

The Commercial Group, XLI, and the Chamber also supported apportioning Xcel's revenue requirement among customer classes according to the Hybrid Method CCOSS. But they each recommended revising Xcel's cost model to incorporate changes they had proposed, as discussed previously; the Commercial Group supported incorporating the changes proposed by XLI, or whichever changes the Commission approved.

Each party proposed a different schedule for transitioning to an apportionment that matches the CCOSS. The Commercial Group supported Xcel's proposal to begin by apportioning revenues to eliminate two-thirds of the difference between the share of revenues a class generates and the share prescribed by the CCOSS. But unlike Xcel, the following year the Commercial Group would apportion revenues to eliminate two-thirds of the remaining difference, and adopt a fully cost-based apportionment thereafter.

XLI favored a still more aggressive transition, eliminating three-quarters of the difference between revenues raised and the CCOSS in the first year, and gradually eliminating the remainder in subsequent years. And the Chamber favored the most aggressive transition of all, adopting a purely cost-based apportionment immediately.

The only non-cost factor considered by these parties was a concern for commercial and industrial customers bearing the cost of "uncompetitive" rates.

3. The Department

The Department recommended implementing Xcel's proposed apportionment through the year 2018, but not the final reapportionment for 2019. Unlike the prior parties, the Department did not recommend eventually adopting a fully cost-based plan, favoring a policy that provided for consideration of non-cost factors as well.

4. The OAG

The OAG developed its proposed apportionment based on three CCOSSs in the record: the Hybrid Method, the Basic Customer Method, and the Peak-and-Average Method. According to the OAG, this foundation made its apportionment more reasonable and stable than proposals based on only one or two CCOSSs.

The OAG stated that it developed its proposal by seeking out patterns among the studies, including customer classes that all the studies identified as bearing too much revenue responsibility, or bearing too little. The OAG also identified classes that two of the three studies identified as bearing too much cost, or too little. (The Residential Class was among those classes.) The OAG then proposed apportionments to bring each of these classes closer to the apportionments indicated by all or most of the studies.

The OAG criticized apportionment proposals that relied on fewer cost models, or that failed to provide for consideration of non-cost factors required by law or past practice. And the OAG argued that its concerns about placing undue reliance on any one CCOSS was heightened in the context of the Settlement, wherein parties arguably refrained from contesting and refining the cost elements as they otherwise would have.

5. ECC

ECC objected to Xcel's proposed apportionment, claiming that it would impose significant burdens on residential customers, especially low-income customers. According to the most recent data that ECC had obtained from Xcel, more than 41,000 of Xcel's residential customers have electric bills that are more than 60 days past due, and the average amount of these outstanding debts is \$473.

Fortunately, ECC reported, many of these customers are eligible for the federal Low Income Home Energy Assistance Program (LIHEAP), which is designed to help them meet their home energy needs.⁴⁹ But ECC also reported that in Minnesota, only about 30 percent of customers that meet the income qualifications for LIHEAP assistance actually receive that assistance.

Consequently ECC recommended that the Commission direct Xcel to inform customers with overdue bills about the availability of LIHEAP assistance. And to better monitor the consequences of any rate increase for residential customers, ECC recommended that the Commission direct Xcel to report every six months on the number of customers with past-due bills, the amount of those bills, and the number of customers disconnected.

C. The Recommendation of the Administrative Law Judge

The ALJ ultimately recommended that the Commission adopt an apportionment that would eventually result in each class bearing its share of Xcel's revenue requirement as indicated by a CCOSS. But the ALJ rejected arguments that competitive pressures on commercial and industrial customers required this result, concluding that allegations of competitive harm had not been adequately demonstrated on the record. Moreover, the ALJ noted that the Department—which generally supported Xcel's proposed apportionment—did not join the other parties in declaring the need for each class fully bear the costs assigned to it by a CCOSS, to the exclusion of all other considerations.

The ALJ recommended an apportionment based on Xcel's CCOSS with modifications, to be implemented over four years, but limiting any increase to a customer class to no more than ten percent per year.

D. Commission Action

All parties have made credible proposals for apportioning Xcel's revenue requirement. The three principal proposals are set forth below:

⁴⁹ Under the LIHEAP program in Minnesota, Xcel provides residential customers with a 50 percent discount on their first 300 kWh consumed each month. *See* Campaign for Home Energy Assistance, Minnesota, at <http://liheap.org/states/mn/> (last visited Feb. 24, 2017).

	2016 Actual Weatherized- Normal ⁵⁰	2016	2017-2018	2019
Xcel Final Proposed Revenue Apportionment				
Residential	36.25%	36.74%	36.97%	37.03%
C&I Non-Demand	3.57%	3.51%	3.51%	3.51%
C&I Demand	59.31%	58.86%	58.61%	58.54%
Lighting	0.87%	0.90%	0.91%	0.91%
TOTAL	100.00%	100.00%	100.00%	100.00%
OAG Final Proposed Revenue Apportionment				
Residential	36.25%	36.03%	35.95%	35.89%
C&I Non-Demand	3.57%	3.51%	3.50%	3.50%
C&I Demand	59.31%	59.56%	59.64%	59.69%
Lighting	0.87%	0.90%	0.91%	0.91%
TOTAL	100.00%	100.00%	100.00%	100.00%
ALJ Final Proposed Revenue Apportionment				
Residential	36.25%	37.27%	37.47%	37.51%
C&I Non-Demand	3.57%	3.44%	3.45%	3.45%
C&I Demand	59.31%	58.39%	58.15%	58.09%
Lighting	0.87%	0.91%	0.93%	0.95%
TOTAL	100.00%	100.00%	100.00%	100.00%

Analysis of the issue of interclass revenue apportionment has been complicated by the fact that parties filed testimony and briefs on the basis of a sales forecast—but actual 2016 sales fell 3.3 percent below forecast, resulting in a shortfall in net present revenue of nearly \$60 million.⁵¹

This degree of variability demonstrates the challenge of establishing interclass revenue apportionments based on anticipated circumstances. Complications involving intraclass revenue apportionments then become compounded as the Commission later establishes the other elements of rate design.

Thus, while a multiyear rate plan provides the flexibility to establish apportionments that change with each year, prudence favors following the Commission’s past practices. So as a preliminary matter, the Commission will act on the basis of the CCOSS data currently available in the record, rather than relying on a new and currently unknown study. And the Commission will set rates with the aid of fixed apportionments that will remain in effect until Xcel’s next rate case.

With that resolved, the Commission must finally determine the appropriate apportionments for each rate class.

⁵⁰ Xcel compliance filing (April 24, 2017).

⁵¹ Xcel Compliance Filing (March 16, 2017).

Each party has presented a plausible theory for apportioning revenue responsibility among classes. The Department and the OAG each developed proposals based on multiple CCOSS methods, acknowledging that no one method provides the best cost allocations for all purposes. And the ALJ found “none of the CCOSSs presented to be sufficiently precise in their measurements” to justify adopting and implementing any study’s apportionment immediately.⁵²

Having given due consideration to each CCOSS in the record, and having reviewed the parties’ proposals, the Commission concludes that the first year of Xcel’s proposed apportionment best balances the competing considerations.

Residential	36.74%
C&I Non-Demand	3.51%
C&I Demand	58.86%
Lighting	0.90%

This apportionment has multiple advantages. For each class, Xcel’s proposed 2016 apportionment coincides with the OAG’s or the ALJ’s 2016 recommendations, or falls between the two. This apportionment will substantially reduce the difference between each class’s costs and its revenues, which should help alleviate the competitive concerns of the Commercial & Industrial classes. This apportionment will promote rate stability by avoiding annual re-apportionments as proposed by Xcel and the OAG.

In particular, the Commission remains mindful of how rate increases affect residential consumers, especially those with low incomes. While the Commission cannot shield every class from the consequences of a rate increase, the Commission concurs with the ECC that more can be done to ensure that low-income consumers gain access to all assistance that is available to them. Fortunately, Xcel has stated its willingness to do its part. Therefore the Commission will direct Xcel to take three steps to aid customers in finding help, and to disclose the extent of financial problems among residential customers:

First, the Commission will direct Xcel to actively reach out to customers with overdue bills in order to inform them about the availability of assistance from LIHEAP.

Second, the Commission will direct Xcel to make a filing within 120 days of this order containing—

- information regarding the availability of LIHEAP funds available for Xcel’s low-income customers,
- data regarding the amount of LIHEAP funding that is not claimed during the year, and
- a plan to improve its outreach to low-income customers.

⁵² ALJ’s Report ¶ 918.

Third, the Commission will direct Xcel to make a filing every six months disclosing—

- The number of past-due residential customers and arrearage information, and
- The number of residential service disconnections.

Additional efforts, bolstered by additional information, will help mitigate the consequences of the rate increase for Xcel’s low-income ratepayers.

XXX. Monthly Customer Charge

A. Introduction

While revenue apportionment focuses on how revenue responsibility should be apportioned *among* customer classes, setting the customer charge addresses how revenues are collected *within* each customer class.

Xcel assesses charges to members of each customer class based on a two- or three-part rate. One part consists of a fixed customer charge that accrues as long as the customer remains a subscriber for Xcel’s services. Another part consists of an energy charge that accrues as the customer consumes more energy. And for certain classes of larger customers, Xcel also assesses a monthly demand charge that grows as the customer’s peak energy consumption grows.

The forecasted sum of the revenues from a class’s customer charge, energy charge, and demand charge must equal the class revenue apportionment. Thus rate design poses a tradeoff: the choice to reduce any one component of these charges must result in an increase to another component. For customers that do not pay a separate demand charge—such as residential customers—an increase in the customer charge will have the effect of reducing the energy charge, and vice versa.

Utilities generally favor increased customer charges to make total bills and revenue collections more stable by reducing the share of a class’s revenue requirement to be recovered on the basis of energy consumption, which varies month to month. However, Minnesota Statutes section 216B.03 directs the Commission to set rates to encourage energy conservation and renewable energy use “to the maximum reasonable extent.” Arguably, this policy favors higher energy charges and lower customer charges.

B. Positions of the Parties

1. Parties Supporting Higher Monthly Customer Charges

Citing Xcel’s CCOSS, both Xcel and the Department favored increasing the monthly customer charge for the Residential Service and Residential Time-of-Day Service rate schedules; Xcel also proposed to increase the customer charge for Small General Service and Small General Time-of-Day Service. Specifically, Xcel proposed an increase of \$2.00 per month, while the Department favored an increase of \$1.25. In support of their positions, these parties variously argued as follows:

Rate design requires balancing economic efficiency with concern for fairness, affordability, stability, and other matters.

Xcel argued that setting the price of energy closer to its variable marginal cost would provide more efficient price signals. It would let the ratepayer bear more of the consequences of a choice to consume or conserve an extra kWh, or to acquire a different source of electricity such as photovoltaic cells. On the other hand, setting the price of energy above its marginal cost would give ratepayers an exaggerated incentive to conserve, move, or seek other energy sources. And as ever more customer-related costs are recovered based on the level of energy consumption, the larger share of these costs will be borne by customers with high energy usage. Xcel claimed that this dynamic results in high-usage customers subsidizing low-usage customers.

Xcel's CCOSS indicated that a revenue stream of \$18.65 per month would be necessary to defray Xcel's average customer-related costs for residential ratepayers. Xcel's and the Department's proposed customer charges would recover only about half this amount. This is consistent with the Commission's decision in Xcel's last rate case, when the Commission established a residential customer charge that would recover roughly half of the average customer-related costs identified in Xcel's CCOSS.

Low-income households tend to consume less energy than average but, according to Xcel, only slightly less. And Xcel argued that many low-income households consume more energy than average.

Xcel and the Department acknowledge that Minnesota Statutes section 216B.03 directs the Commission to set rates to encourage energy conservation and renewable energy use "to the maximum reasonable extent." But they argue that recovering ever more costs on the basis of energy consumption eventually becomes unreasonable because it requires an excessive sacrifice of economic efficiency, fairness, affordability, and other concerns.

2. Parties Opposing Higher Customer Charges

AARP, the CEO, ECC, Minneapolis, the OAG, and the SRA opposed increasing the monthly customer charge for the Residential and Small General Service tariffs. Indeed, AARP and the OAG argued for reducing the charge by \$1.00 per month starting in 2016. And the OAG argued for reducing the charge by an additional \$1.00 per month by the end of the multiyear rate plan's third year.

These parties argued variously that rate designs with higher energy charges and lower monthly customer charges maintain the health and safety of low-income customers, promote affordability, and enhance customer control over energy bills. They argued that the traditional rationale for higher residential customer charges—ensuring stable revenues for the utility—is obviated by Xcel's revenue-decoupling pilot program, which moderates Xcel's risk that mild weather or changes in usage may depress electricity sales.

These parties argued that Minnesota Statutes section 216B.03—directing the Commission to set rates to encourage conservation to the maximum reasonable extent—favors rate designs with higher energy charges and lower customer charges. That is because higher energy costs will tend to discourage energy consumption and reward energy conservation. In contrast, a CEO study found that Xcel's favored rate design would increase energy sales by 0.8 percent—effectively nullifying two-thirds of the state's goal in establishing the Conservation Improvement Program of reducing energy sales by 1.2 percent.

The CEO argued that CCOSSs are designed to aid revenue apportionment among customer classes, and are not intended for the purpose of rate design within classes. If the Commission wants to identify a utility's average customer costs, the CEO and OAG argued, it should identify the specific plants and services that are required to connect a new customer to a utility's network, or maintain an additional customer on the network. Of all the CCOSSs in the record, the CEO and OAG argued that the Basic Customer Method comes closest to providing this analysis. The OAG identified average customer-related costs of between \$3.00 and \$5.00 per month, while the CEO's study estimated the cost at \$5.97 per month

Finally, it was undisputed that low-income households tend to consume less energy than average households. As noted previously, most low-income households do not receive LIHEAP assistance. These parties argued that the Commission should design rates to minimize the burdens to those least able to bear them. That would mean keeping customer charges low, even at the expense of higher energy charges.

C. The Recommendation of the Administrative Law Judge

The ALJ rejected the claim that the record demonstrated the economic efficiency of any given monthly customer charge. The ALJ acknowledged that by setting prices equal to marginal cost, the Commission could let customers bear the social cost of increasing consumption, and the social benefits of conserving. But the ALJ found that marginal cost could not be determined on the basis of the historical cost data in the record. Therefore the ALJ found no support for arguments purporting to show how a given fixed customer charge would promote economic efficiency.

Having rejected the arguments supporting a higher monthly customer charge, the ALJ also declined to recommend lowering the charge due to the adverse consequences for high-usage households. Consequently the ALJ recommended that the Commission retain the current schedule of customer charges for residential and small commercial customers.

D. Commission Action

The Commission concurs with the ALJ that the goal of setting efficient price signals would ideally be informed by a rigorous calculation of marginal cost, and that this number can be difficult to derive from the record of a rate case. But more importantly, sending efficient price signals is merely one of the Commission's objectives. Setting the price of energy at the marginal cost of production, and setting the customer charge at the marginal cost to connect or maintain a customer, may not permit a utility to recover its cost of service.

The Commission also seeks to set Xcel's rates in a manner that would permit a prudently-managed utility serving Xcel's service area to be able to recover its costs and earn a fair return. CCOSSs are designed to aid a regulator's efforts to apportion revenue responsibility among classes of customers. And the rate-design process is designed to ensure that the utility's rates, multiplied by the amount of service the utility is forecast to provide, will generate the revenues apportioned to each class.

Minnesota Statutes section 216B.03 directs the Commission to design rates to encourage conservation and the use of renewable energy. Minnesota Statutes section 216B.16, subdivision 15, directs the Commission to consider ability to pay when designing rates. The Commission also values rate continuity and the avoidance of rate shock. These objectives conflict.

In sum, the Commission lacks the information that would let it achieve perfect economic efficiency, and moreover, the Commission has a duty to pursue revenue objectives that are inconsistent with marginal-cost pricing. Nevertheless, the Commission may make reasonable inferences about which rate proposals are more likely to send appropriate price signals, even if imperfectly.

Having reviewed the arguments of the parties and balanced the competing considerations, the Commission is not persuaded that any party has demonstrated the need to alter the monthly customer charges that Xcel assesses on residential and small business customers—whether to increase or decrease them. Consequently those monthly customer charges will be retained.

XXXI. Interruptible Service and Discounts

A. Introduction

Interruptible customers forgo firm electric service in exchange for a discount. That is, customers who subscribe for interruptible service receive electricity at a lower price than customers receiving firm service, but they agree to promptly curtail their consumption of electricity upon request.

Xcel offers two tiers of Interruptible Service for its Commercial & Industrial Demand customers. Under Tier 1, a customer signs a ten-year contract with the option of canceling the contract after three years' notice, and a guarantee that Xcel will not interrupt the customer's service for more than 150 hours. Under Tier 2, the customer signs a five-year contract with the option of cancelling after six months' notice, and a guarantee that Xcel will not interrupt the customer's service for more than 80 hours.

Interruptible service benefits both the utility and the customer. Xcel gains the benefit of reduced supply-side capacity obligation resulting from the option to interrupt service to an interruptible customer.

According to MISO rules, utilities must have planning resource credits or accredited generating capacity to reliably serve its firm customers. Interruptible customers that are accredited with MISO reduce the amount of supply-side capacity that Xcel must maintain on its system.

At the same time, the customer gains the benefit of receiving electric service at a discounted rate. The interruptible discount increases as the customer's average July and August peak-hours maximum controllable demand increases. As part of the Settlement, Xcel proposed increasing controllable demand charges in 2016, 2017, and 2019—but proposed increasing the interruptible discount only in 2016, and only by 0.6 to 2.0 percent, with an average increase of 1.84 percent. Parties disagree about whether the overall terms of interruptible service are sufficient to attract the appropriate level of participation.

B. Positions of the Parties

1. The Chamber and XLI

The Chamber and XLI argued that Xcel was mismanaging its interruptible service, making it less attractive even as it becomes more important. They variously argued as follows:

- Utilities throughout the US, including Xcel, are making plans to retire their coal-fired generators. This change will strain the capacities of the remaining generators, and enhance the value of customers willing to subscribe for interruptible service.
- Xcel has begun testing its interruptible-service program by calling on subscribers to fully curtail service at short notice, contrary to MISO's tariff and business practices. Apparently many large commercial and industrial customers found it burdensome to shut down their operations merely for a test. By March 2016, Xcel's system lost 45 megawatts (MW) of interruptible load: 78 customers canceled their contracts and 333 customers chose to reduce the amount of load subject to interruption. Arguably this has reduced Xcel's flexibility for managing emergencies, and increased the amount of load for which Xcel must secure supply-side capacity resources.
- As previously noted, Xcel proposed increasing the demand charge for its demand-metered customers throughout this multiyear rate plan, but proposed only a single, modest increase in the interruptible discount. When Xcel increases its demand charge at a faster rate than it increases the discount for interruptible service, arguably Xcel is diluting the value of the discount.

While the Chamber and XLI were in substantial agreement about the nature of the problem, they proposed different remedies.

XLI objected to the size of Xcel's proposed increase in the interruptible discount, and recommended that the Commission maintain the current demand charge for Tier I, Short-Notice interruptible service. Comparing the benefits of XLI's interruptible load to the cost and benefits of having a small generator on hand, XLI argued that Xcel's interruptible discount undervalues the benefits provided by interruptible customers.

In contrast, the Chamber withdrew its objections to Xcel's 2016 proposed change to the interruptible discount. But the Chamber maintained that when Xcel increases the demand charges for the Commercial and Industrial Demand class in 2017 and 2018, it should increase the interruptible discount by the same percentage.

The Chamber also recommended that Xcel discontinue its practice of subjecting interruptible customers to spot checks that require customers to shut down their operations. The Chamber claimed that mock tests, as specified in the MISO tariff and business practices manuals, would suffice.

2. The Department

The Department recommended that the Commission approve Xcel's proposed increase in the discount rate. The Department observed that Xcel's infrequent interruption of service to interruptible customers may not be maximizing the program's benefits to the system. The Department concluded that the increased discount would help moderate the consequences of the proposed rate increase for the Commercial & Industrial Demand class, and maintain the current balance of costs and benefits reflected in the terms for firm and interruptible service.

The Department suggested that the challenge of establishing the optimal terms for Xcel's interruptible service, and the optimal strategies for exercising the option to interrupt service, might be addressed more productively in the Commission's current docket exploring changes to Xcel's rate design.⁵³

3. Xcel

Xcel defended its proposed rate increase for the Commercial & Industrial Demand class, and its proposed increase to the interruptible discount.

Xcel stated that it disagrees with the Chamber's calculations of appropriate discount amounts for 2017 and 2018. However, Xcel supported the proposal to make proportionate increases to the interruptible discount in 2017 and 2018 when it implements increases to the demand charge.

In response to the Chamber's proposal to eliminate mandatory testing of its interruptible-service customers and instead conduct mock tests, Xcel noted that mandatory testing for interruptible service customers is provided for by Xcel's tariff. Moreover, Xcel stated that such testing is appropriate and advisable.

4. The Recommendation of the Administrative Law Judge

The ALJ acknowledged that interruptible customers permit Xcel to reduce the amount of generation capacity it needs to meet its peak demand, but did not agree that the value of the interruptible discount must reflect the avoided cost of that standby power. Rather, the ALJ concluded that the size of the discount reflects a market-based approach to valuing interruptible load in order to attract the optimal amount of interruptible load.

The ALJ shared the Chamber's and XLI's concern about the number of Xcel customers that recently switched from interruptible service to firm service, but could not establish a standard for judging whether Xcel's current interruptible load was optimal or not.

The ALJ agreed with the Department that the interruptible load program should be reviewed in the Commission's investigation into Xcel's rate design.

Finally, the ALJ concurred with the recommendation to increase the interruptible discount in proportion to any increase in the demand charge for the Commercial & Industrial Demand class after 2016. If the Commission were to adopt the Settlement, this would mean increasing the interruptible discount in 2017 and 2019.

5. Commission Action

XLI argued that Xcel's rate proposals fail to regard interruptible service as the equivalent of supply-side capacity, and thus Xcel neglected to offer a discount that is commensurate with the benefit. In response, the Department and the ALJ concluded that the optimal size of Xcel's discount cannot be determined on the basis of an avoided-cost calculation. The Commission agrees in part: Interruptible service reduces Xcel's supply-side capacity resource needs, and thus

⁵³ *In the Matter of an Alternative Rate Design Stakeholder Process for Xcel Energy*, Docket No. E-002/CI-15-662 (Xcel's Rate Design Docket).

optimal size of the interruptible-service discount could be determined on the basis of XLI's avoided-cost calculation. But additional factors should be considered.

Evaluating the terms for interruptible service is akin to evaluating alternatives in a utility's resource plan. It requires comparing (a) the benefits to the utility from a vendor—that is, a customer willing to subscribe for interruptible service—to (b) the costs of securing those benefits. If the terms are not sufficiently attractive (discount too low, testing too onerous, service interruptions too frequent), then Xcel will not be able to attract and maintain enough participation in the program, and will have to acquire additional supply-side capacity instead. But if the terms are made too attractive (discount needlessly large, testing too lax, service maintained even when unduly expensive to the utility), then Xcel will needlessly forgo revenues and savings, and may imperil system reliability.

Given the delicacy of this trade-off, this Commission—like the Chamber, the Department, and the ALJ—is inclined to give Xcel leeway in this case to set the terms for interruptible service. Consequently the Commission will approve an increase in the discount level for 2016 as proposed by Xcel. Xcel claims that increasing the discount by an average of 1.84 percent would help maintain the appropriate balance of costs and benefits offered by its firm and interruptible services. The Commission finds this argument to be reasonable, and will affirm it.

But this balance would be upset if, as planned, Xcel were to increase its demand charges without making a corresponding increase in the interruptible discount. For this reason, the Commission will also adopt the recommendation of the Chamber, the Department, and the ALJ that as Xcel increases the demand charges for the Commercial & Industrial Demand class, it should increase the size of the interruptible credit in the same proportion. Because the Settlement does not provide for rate increases in 2018, these increases would occur in 2017 and 2019.

Finally, the Chamber and XLI objected to Xcel's practice of periodically requiring interruptible customers to fully curtail their consumption of electricity in order to test their ability to do so. The Commission is open to the possibility that Xcel could obtain the necessary assurances without compelling commercial and industrial customers to take the final step and curtail their operations. If MISO's accreditation policies do not require that type of testing, the Commission will not either.

Consequently the Commission will direct Xcel to conduct testing of interruptible customers consistent with the testing required by MISO's tariffs and Business Practice Manuals, and to revise its tariff accordingly.

XXXII. Miscellaneous Rate-Design Topics

Finally, the ALJ recommended that the Commission direct parties to take additional procedural steps with respect to the following four rate-design topics:

- *Time-of-Use rates for Commercial & Industrial classes:* Refer the matter to Xcel's alternative-rate-design proceeding.
- *Time-of-Use rates for Residential class:* Refer the matter to Xcel's alternative-rate-design proceeding.

- *The Renew-A-Source program for Commercial & Industrial classes:* Initiate discussions among the parties, and refer the matter to Xcel’s alternative-rate-design proceeding.
- *The BIS Rider:* Initiate an investigation.

Having reviewed the arguments of the parties, the Commission is not persuaded that the record justifies directing parties to take additional procedural steps on these matters. The parties may exercise their own discretion in choosing what additional relief to pursue, if any.

ILLUSTRATIVE FINANCIAL SCHEDULES

A. Gross Revenue Deficiency

Based on the above findings, the Commission concludes that, as shown below, the 2016 test year total gross revenue deficiency is \$134,966,000, the 2017 and 2018 plan year total gross revenue deficiency is \$194,824,000 and the 2019 plan year total gross revenue deficiency is \$244,721,000:

Revenue Deficiency - Minnesota Jurisdiction Test Year Ending December 31, 2016 and 2017-2019 Plan Years (\$000’s)

Line No.		2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Plan Year
1	Average Rate Base	\$7,443,512	\$7,426,751	\$7,293,821	\$7,202,334
2	Operating Income	\$413,030	\$371,587	\$368,756	\$338,552
3	AFUDC	\$34,096	\$40,744	\$34,150	\$27,894
4	Total Available for Return	\$447,126	\$412,331	\$402,906	\$366,445
5	Overall Rate of Return (Line 4 / Line 1)	6.01%	5.55%	5.52%	5.09%
6	Required Rate of Return	7.07%	7.09%	7.09%	7.08%
7	Required Operating Income (Line 1 x Line 6)	\$526,256	\$526,557	\$517,132	\$509,925
8	Income Deficiency (Line 7 - Line 4)	\$79,130	\$114,226	\$114,226	\$143,480
9	Gross Revenue Conversion Factor	1.705611	1.705611	1.705611	1.705611
10	Revenue Deficiency (Line 8 x Line 9)	\$134,966	\$194,824	\$194,824	\$244,721
11	Retail Related Revenues Under 2016 Present Rates	\$2,956,319	\$2,956,319	\$2,956,319	\$2,956,319

B. Rate Base Summary

Based on the above findings, the Commission concludes that, as shown below, the appropriate rate bases are \$7,443,512,000 for the 2016 test year, \$7,426,751,000 for the 2017 plan year, \$7,293,821,000 for the 2018 plan year, and \$7,202,334,000 for the 2019 plan year:

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2016 and 2017-2019 Plan Years
(\$000's)

Line No.		2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Plan Year
	ELECTRIC PLANT IN SERVICE				
1	Production	9,178,231	9,443,128	9,749,355	10,060,608
2	Transmission	2,203,520	2,262,072	2,301,595	2,397,725
3	Distribution	3,272,959	3,391,796	3,516,302	3,658,370
4	General	727,748	777,297	827,938	888,530
5	Common	540,996	639,611	725,535	781,187
6	Total Utility Plant In Service	15,923,454	16,513,905	17,120,725	17,786,420
	RESERVE FOR DEPRECIATION				
7	Production	4,941,309	5,290,771	5,644,011	6,015,790
8	Transmission	533,116	552,513	585,833	619,062
9	Distribution	1,232,993	1,277,293	1,333,146	1,391,483
10	General	267,760	328,863	390,194	451,746
11	Common	268,091	313,919	362,619	412,713
12	Total Reserve For Depreciation	7,243,269	7,763,360	8,315,803	8,890,795
	NET PLANT IN SERVICE				
13	Production	4,236,922	4,152,357	4,105,344	4,044,818
14	Transmission	1,670,404	1,709,559	1,715,763	1,778,663
15	Distribution	2,039,966	2,114,503	2,183,156	2,266,887
16	General	459,988	448,435	437,744	436,784
17	Common	272,905	325,691	362,916	368,473
18	Net Utility Plant In Service	8,680,185	8,750,545	8,804,922	8,895,625
19	Construction Work in Progress	453,110	482,754	422,411	380,350
20	Accumulated Deferred Income Taxes	(1,911,697)	(2,023,988)	(2,153,354)	(2,302,072)
	Other Rate Base Items				
21	Cash Working Capital	(100,003)	(107,935)	(111,985)	(111,130)
22	Material & Supplies	135,797	135,797	135,797	135,797
23	Fuel Inventory	73,476	73,476	73,476	73,476
24	Non-Plan Assets & Liabilities	(3,716)	5,666	15,903	27,456
25	Customer Advances	(5,562)	(5,562)	(5,562)	(5,562)
26	Customer Deposits	(28,127)	(28,127)	(28,127)	(28,127)
27	Prepayments	89,307	86,772	86,374	85,941
28	Regulatory Amortizations	60,741	57,353	53,966	50,579
29	Total Other Rate Base	221,913	217,440	219,842	228,430
30	TOTAL AVERAGE RATE BASE	7,443,512	7,426,751	7,293,821	7,202,334

C. Operating Income

Based on the above findings, the Commission concludes that, as shown below, the appropriate operating incomes are \$447,126,000 for the 2016 test year, \$412,331,000 for the 2017 plan year, \$402,906,000 for the 2018 plan year, and \$366,445,000 for the 2019 plan year:

Operating Income Summary - Minnesota Jurisdiction Test Year Ending December 31, 2016 and 2017-2019 Plan Years (\$000's)

Line No.		2016 Test Year	2017 Plan Year	2018 Plan Year	2019 Plan Year
	OPERATING REVENUES				
1	Retail Revenue	2,955,675	2,955,675	2,955,675	3,051,778
2	Interdepartmental	644	644	644	672
3	Other Operating Revenue	593,580	618,227	660,562	687,000
4	Total Operating Revenue	3,549,899	3,574,546	3,616,881	3,739,450
	EXPENSES				
	Operating Expenses				
5	Fuel & Purchased Energy	1,001,096	1,001,136	1,001,199	1,125,206
6	Power Production	679,459	685,084	687,737	691,533
7	Transmission	204,923	209,530	217,148	243,697
8	Distribution	108,023	110,120	112,784	111,186
9	Customer Accounting	49,315	49,956	50,820	50,555
10	Customer Service and Information	94,968	94,983	94,998	95,067
11	Sales, Econ Dev, & Other	69	70	71	69
12	Administrative and General	206,324	211,033	216,787	224,433
13	Total Operating Expenses	2,344,178	2,361,911	2,381,546	2,541,744
15	Depreciation	449,537	522,206	540,936	568,522
16	Amortization	39,359	39,273	39,273	21,871
	TAXES				
17	Property Taxes	178,439	186,760	192,275	198,796
18	Deferred Income Tax & ITC	110,661	127,890	122,206	107,334
19	Federal & State Income Tax	(12,855)	(63,320)	(56,874)	(67,264)
20	Payroll & Other	27,550	28,238	28,763	29,896
21	Total Taxes	303,795	279,569	286,371	268,761
22	Total Expenses	3,136,869	3,202,959	3,248,126	3,400,898
22	Allowance for Funds Used During Construction (AFUDC)	34,096	40,744	34,150	27,894
24	Total Operating Income	447,126	412,331	402,906	366,445

ORDER

1. The Commission adopts the ALJ's Findings of Fact, Conclusions of Law, and Recommendations to the extent that the ALJ's Report is consistent with the decisions herein.
2. The Commission hereby approves the August 16, 2016 Stipulation of Settlement in its entirety.
3. Xcel shall work with Commission and Department staff to develop a capital-projects true-up compliance reporting tool that meets the regulatory needs of the agencies, to be filed annually.
4. The Commission hereby grants a variance to Minn. R. 7825.3300; Xcel shall use an annual 4.81% interest rate to calculate interim-rate refunds.
5. Xcel shall make a compliance filing once the Mankato II in-service date becomes certain. If the in-service date does not materialize by 2019, the compliance filing should include the delay's 2019 revenue-requirement impact and how Xcel proposes to address it.
6. Within 90 days of the date of this order, Xcel shall make a compliance filing comparing final rate case expenses to the requested \$3.34 million.
7. Xcel shall file, as a comparison, a true-up calculation based on actual (not weather-normalized) sales and revenue throughout the term of the multiyear rate plan.
8. A separate proceeding (Docket No. E-002/CI-17-401) will identify and develop performance metrics and standards, and potentially incentives, to be implemented during the multiyear rate plan. The Commission delegates to the Executive Secretary to issue notice(s), set schedules, and designate comment periods.
9. Regarding the Class Cost-of-Service Study:
 - a. Xcel need not file a revised CCOSS for purposes of apportioning revenues among customer classes in this docket.
 - b. Xcel shall report on methods to measure losses for Xcel's next rate case.
 - c. In Xcel's next docket revising its Renewable Development Fund rider, any party may raise the issues identified by the Chamber regarding the allocation of RDF rider costs.
 - d. In Xcel's next docket revising its Conservation Improvement Program rider, any party may raise the issues identified by the Chamber and XLI regarding the allocation of CIP costs.
 - e. For purposes of Xcel's next rate case, Xcel shall adopt the recommendations of the ALJ with the following exceptions:
 - i. Xcel need not adopt the ALJ's recommendations regarding the classification and allocation of distribution costs.
 - ii. Xcel shall base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak, incorporating any future changes to MISO's method for calculating the system peak.

10. Xcel shall apportion revenue responsibility among its customer classes throughout the duration of the multiyear rate plan as follows:

Residential	36.74%
C&I Non-Demand	3.51%
C&I Demand	58.86%
Lighting	0.90%

11. To mitigate the consequences of residential rate increases, Xcel shall do the following:
- a. Make a filing within 120 days of this order containing
 - information regarding the availability of Low-Income Home Energy Assistance Program (LIHEAP) funds available for Xcel's low-income customers,
 - data regarding the amount of LIHEAP funding that is not claimed during the year, and
 - a plan to improve its outreach to low-income customers
 - b. Make a filing every six months containing
 - The number of past-due residential customers and arrearage information and
 - The number of residential service disconnections
 - c. Actively reach out to past-due customers in order to inform them about the availability of assistance from LIHEAP.
12. Xcel shall maintain its current monthly customer charge for Residential and Small Commercial customers.
13. Regarding interruptible service, the Commission takes the following actions:
- a. Authorizes Xcel to implement its original proposal for increases in its interruptible service discounts of between 0.6 and 2.0 percent with an average of 1.84 percent for the 2016 test year.
 - b. Approves Xcel's 2016 proposed increases, but require that the 2017 and 2019 interruptible service discounts increase by the same percent increase as the proposed controllable demand charges.
 - c. Requires Xcel to modify its interruptible-program testing requirements to be consistent with the testing provided for in the tariffs and Business Practices Manuals of the Midcontinent Independent System Operator, Inc.

14. The Commission takes no action on the following proposals:
 - a. Changing the definition of “Peak Period” for Commercial & Industrial customers’ Time-of-Use rates.
 - b. Initiating a Time-of-Use pilot program for Residential customers.
 - c. Developing a Renew-A-Source program for Large Industrial customers.
 - d. Modifying the BIS Rider, or initiating an investigation of that rider.

15. Within 30 days, Xcel shall make the following compliance filings:
 - a. Revised schedules of rates and charges reflecting the revenue requirement and the rate-design decisions herein, along with the proposed effective date, and including the following information:
 - i. Breakdown of Total Operating Revenues by type;
 - ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:
 1. Total revenue by customer class;
 2. Total number of customers, the customer charge, and total customer charge revenue by customer class; and
 3. For each customer class, the total number of energy- and demand-related billing units, the per-unit energy and demand cost of energy, and the total energy- and demand-related sales revenues.
 - iii. Revised tariff sheets incorporating authorized rate-design decisions; and
 - iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.
 - b. A revised base cost of energy, supporting schedules, and revised fuel-adjustment tariffs to be in effect on the date final rates are implemented.
 - c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.
 - d. A computation of the CCRC based upon the decisions made herein.
 - e. A schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.
 - f. A proposal to make refunds of interim rates to affected customers consistent with the Commission’s decisions herein.

16. Comments may be filed on all compliance filings within 30 days of the date they are filed.
17. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary



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