BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota

ISSUE DATE: June 9, 2014

DOCKET NO. G-008/GR-13-316

FINDINGS OF FACT,
CONCLUSIONS, AND ORDER

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PROCEDURAL HISTORY

I. Initial Filings and Orders

On August 2, 2013, CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas (CenterPoint or the Company) filed this general rate case seeking an annual rate increase of some $44,322,000, or approximately 5%. The filing included a proposed interim rate schedule.

On the same date, the Company filed a petition to establish a new base cost of gas for the period during which interim rates would be in effect; that petition was granted by order dated September 23, 2013.[1]

Also on September 23, 2013, the Commission issued three orders in this case:

- an order finding the rate case filing substantially complete, requiring supplemental filings on specific issues, 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
- 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:

[1] *In the Matter of a Petition by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas to Establish a New Base Cost of Gas and Reset the Purchased Gas Adjustment to Zero, to Coincide with the Implementation of Interim Rates in the General Rate Case Filing*, Docket G-008/MR-13-674, Order Setting New Base Cost of Gas (September 23, 2013).

- CenterPoint Energy, represented by Eric F. Swanson and David M. Aafedt, Winthrop and Weinstine, P.A.

- Minnesota Department of Commerce, Division of Energy Resources (Department), represented by Julia E. Anderson, Linda S. Jensen, and Peter E. Madsen, Assistant Attorneys General.

- Antitrust and Utilities Division of the Office of the Attorney General (OAG), represented by Ian Dobson, Assistant Attorney General, and Karen Olson, Deputy Attorney General.

- Suburban Rate Authority, represented by James M. Strommen, Kennedy & Graven, Chartered.

- Fresh Energy and Izaak Walton League—Midwest Office, and Natural Resources Defense Council, participating jointly as "Environmental Intervenors" and represented respectively by Elizabeth Goodpaster, Attorney at Law, Minnesota Center for Environmental Advocacy, and Samantha Williams, Attorney at Law, Natural Resources Defense Council.

III. Proceedings Before the Administrative Law Judge

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

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held evidentiary hearings in Saint Paul on January 14-16, 2014. After the hearings the parties filed initial briefs, reply briefs, and proposed findings of fact.
The ALJ also held five public hearings in the case, on the dates and at the locations set forth below:

- Brainerd—December 2, 2013
- Bloomington—December 3, 2013
- Mankato—December 4, 2013
- Brooklyn Center—December 9, 2013
- Minneapolis—December 10, 2013

IV. Public Comments

The Administrative Law Judge held five public hearings; 31 members of the public attended and 12 spoke. Representatives of CenterPoint, the Department, the Office of the Attorney General, and the Commission also attended, to answer questions and receive public input. Seventy-eight members of the public submitted written comments.

Nearly all commenting members of the public were opposed to the rate increase proposed by the Company. The objections raised most frequently were that the increase would cause hardship for low-income households, especially senior citizens relying on Social Security benefits; that customers' conservation efforts were not being rewarded and might therefore be discouraged; that the Company was not controlling costs sufficiently, especially in the area of executive compensation; that falling gas prices and the recent increase in domestic production should lead to lower bills; that the proposed increase in the residential customer charge would disproportionately affect low-usage customers; and that the Company should scale back its profit expectations in these challenging economic times.

V. Proceedings Before the Commission

On April 9, 2014, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law and Recommendations (the ALJ's Report). All parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700.

On May 5 and May 8, 2014, the Commission heard oral argument from and asked questions of the parties. On May 8, 2014, 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.[2] 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.[3] 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 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, ranging 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.

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

[3] *In the Matter of the Request of Interstate Power Company for Authority to Change its Rates for Gas Service in Minnesota*, 574 N.W.2d 408, 411 (Minn. 1998).

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 its 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.[4]

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.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

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:

> 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

[4] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987) (citation omitted).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

> to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[7]

II. Summary of the Issues

This rate case was driven mainly by substantial new infrastructure investments made by the Company in response to the aging of its infrastructure and new state and federal pipeline safety regulations. No party challenged the reasonableness or prudence of these investments, which are discussed below.

In its Notice and Order for Hearing and in its Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing, the Commission directed the Company to address five non-standard rate-case issues and to file supplemental testimony on three other issues specific to this case. Those issues are addressed below.

Some initially contested issues were largely resolved by the time of oral argument. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; she recommended accepting them. The Commission concurs.

Several issues were resolved by the parties, subject to compliance filings or filings in the next rate case: the Company's updated Conservation Cost Recovery Charge; the final interest-synchronization adjustment; test-year fleet-fuel prices; inter-jurisdictional cost allocation methodology and the resulting allocation factors; travel, training, and related employee expenses under Minn. Stat. § 216B.16, subd. 17; and projected sales and margins related to the Company's liquefied natural gas contracts.

Other issues remained contested. The following issues were either contested or otherwise require discussion.

Financial Issues

- ***Pension Plan Discount Rate*—**How should the Commission set the pension plan discount rate, the interest rate used to adjust the plan's anticipated future benefit to present dollars, to reflect the time value of money?

- ***Non-Qualified Pension Expense*—**Should the Company be permitted to recover pension costs that exceed tax-deductible levels set by the IRS?

- ***Non-Qualified Saving Plan Expense*—**Should the Company be permitted to recover retirement-savings-plan costs that exceed tax-deductible levels set by the IRS?

- ***Incentive Compensation*—**Should the Company be permitted to recover the costs of its long-term and short-term incentive compensation plans? Should the Company be required to refund to ratepayers incentive compensation amounts built into rates and not paid to employees?

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[7] *In the Matter of the Petition of Minnesota Power & Light Company, d.b.a. Minnesota Power, for Authority to Change its Schedule of Rates for Electric Utility Service Within the State of Minnesota,* 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted).

- ***Marketing Program***—Should the Company be permitted to recover the cost of three marketing programs designed to promote the use of natural gas over electricity for specific applications?

- ***Income Taxes***—Should the Company be permitted to include in its income tax adjustments taxes paid for non-deductible but rate-recoverable costs?

- ***Inflation Rates***—Are the inflation factors used by the Company in calculating test year costs reasonable and prudent?

- ***Investor Relations***—What portion of the Company's shareholder- and investor-relations costs should be recovered from ratepayers?

- ***Impact of Raising Reconnection Fee***—Is it appropriate to update test-year revenues to reflect the effect of raising the Reconnection Fee when final rates go into effect?

- ***Over-Recovered 2008 Rate Case Costs***—Is the amount of the 2008 rate case costs over-recovered by the Company the difference between (a) the amount the Company recovered and the amount the Commission authorized the Company to recover or (b) the amount the Company recovered and the amount the Company actually spent on the 2008 rate case? How should the Company refund the over-recovered rate case costs to ratepayers and at what interest rate?

- ***Current Rate Case Costs***—What portion of the Company's rate case costs should be recovered from ratepayers?

- ***Rate-Case-Cost Amortization Period and Related Issues***—Over what period of time should the Company's rate case costs be amortized? Should the recovery of approved rate case costs be tracked and any over-recovery refunded to ratepayers? If so, at what interest rate?

- ***Sales Forecast and Weather Normalization***—Should the Commission accept, reject, or modify the Company's sales forecast, especially its ten-year weather normalization method?

Cost of Capital Issue

- ***Return on Equity***—What is a fair and reasonable rate of return on equity for this company, on this record, at this time?

Class Cost of Service Study (CCOSS) Issues

- ***Adequacy of the CCOSS***—Is the Company's CCOSS adequate for purposes of this rate case?

- ***CCOSS Treatment of Income Tax***—Does the Company's CCOSS comply with the order in its last rate case requiring it to allocate income taxes on the basis of the taxable income attributable to each customer class, not on the basis of rate base?

- ***Minimum System Study in the CCOSS***—Was the Company's use of two-inch pipe in the minimum system study it conducted for its CCOSS reasonable for purposes of this case?

- ***CCOSS Treatment of Sales Expense, FERC Accounts 911-916***—Was the Company's inter-class allocation of sales costs by number of customer locations the most reasonable allocation method in the record?

- ***CCOSS Treatment of Customer Accounts Expense, FERC Accounts 901-905***—Was the Company's inter-class allocation of customer accounts expenses by number of customers and investment-weighted number of locations the most reasonable allocation method in the record?

- ***CCOSS Treatment of Customer Service and Informational Expense, FERC Accounts 907, 909, 910***—Was the Company's inter-class allocation of customer service and informational expense by number of customer locations the most reasonable allocation method in the record?

- ***CCOSS Treatment of Regulatory Commission Expense, FERC Account 928***—Was the Company's inter-class allocation of regulatory commission expense by number of customer locations the most reasonable allocation method in the record?

Rate Design Issues

- ***Revenue Allocation***—Should the revenue allocation method approved in this case move the revenue responsibilities of customer classes closer to cost?

- ***Revenue Decoupling***—Should the Commission direct the Company to implement a rate design decoupling revenues and gas sales?

- ***Residential and Small Volume Commercial and Industrial Customer Charges***—Should the residential or Small Volume Commercial and Industrial customer charges be increased to more closely approximate the fixed costs of service, and if so, to what level?

- ***Small Volume Dual Fuel, Large Volume Dual Fuel, and Large Volume Sales and Transportation Customer Charges***—Should the customer charges for the Small Volume Dual Fuel, Large Volume Dual Fuel, and Large Volume Sales and Transportation classes be adjusted to more closely approximate the fixed costs of service, and if so, to what levels?

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

III. Infrastructure Investment Program

Nearly three-fourths of the Company's identified revenue deficiency arises from certain expenses related to capital projects. According to the Company, its Transmission and Distribution Integrity Management Projects represent ongoing, increased spending on efforts to modernize, maintain, and replace pipeline to meet state and federal safety and reliability standards. The necessity and prudence of these expenses were uncontested by any party. The increased costs of infrastructure and the associated expense adjustments, such as depreciation and taxes, make up approximately $32 million of the Company’s proposed $44,322,000 revenue increase.

The Company testified in detail about the nature and magnitude of these projects and their related expenses. The projects include:

- Replacement or repair of high-pressure transmission pipeline that rings the Twin Cities metro area (the “Beltline Project”). The Beltline Project will replace 18.6 miles of transmission line over five years with a planned cost of over $26 million in each of 2013 and 2014. After the initial five-year period, the Company plans to repair or replace an additional 40.1 miles of Beltline pipeline over fifteen years. According to the Company the pipelines scheduled for replacement were installed between 1930 and 1960.
- Replacement or protection of 459 miles of bare steel mains over a twenty-year period, with planned annual costs of $3.9 million in 2013 and 2014.
- Replacement of 25 miles of cast iron mains over a seven-year period starting in 2013, with planned annual costs of approximately $3 million in 2013 and 2014.
- Replacement of eight miles of PVC mains over a five-year period, with planned annual costs of $500,000 in 2013 and 2014.
- Replacement of copper service lines over an eight-year period, with planned annual costs of $300,000 in 2013 and 2014.
- Replacement of 89,700 indoor residential meters over a fifteen-year period, with a planned annual cost of $2 million in 2013 for 830 replacements, ramping up to $8 million in 2014 for 3,330 replacements (an average of slightly more than $2,400 per replaced meter). The Company testified that in most cases it expects that the service line will also be replaced.
- Installation of remote-controlled valves, cathodic protection systems, and Supervisory Control and Data Acquisition (SCADA) systems. The planned costs for these smaller projects total $1 million in 2013 and $1.2 million in 2014.

The ALJ found that the Company’s testimony established these costs as reasonable and necessary, and recommended they be included among the Company’s test year expenses. The Commission agrees that these projects are necessary to ensure reliable natural gas service and compliance with pipeline safety standards. It is prudent to move ahead with these capital improvements. Accordingly, the Commission will authorize the Transmission and Distribution Integrity Management Projects’ expenses to be included in the Company’s test year.

IV. Non-Standard Rate-Case Issues Identified in Initial Orders

In its Notice and Order for Hearing and in its Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing, the Commission directed the Company to address five non-standard rate-case issues and to file supplemental testimony addressing three other issues specific to this case.

The Company addressed the issues identified and filed the supplemental testimony required; the parties and the ALJ examined them in the course of this proceeding. These issues and filings are treated below.

1) ***Operating Income*—**What is the appropriate number to be used for 2012 operating income in the rate case—the number included in Schedule C-2(b) of the Company's rate case filing ($33,947,000) or the number included in the Company's 2012 Jurisdictional Annual Report ($36,900,000) filed in Docket No. E,G-999/PR-13-04?

The Company addressed this issue in the Supplemental Direct Testimony of Kirk R. Nesvig. Mr. Nesvig explained that the difference between the two numbers was mainly due to the exclusion of the Conservation Improvement Program financial incentive from the Jurisdictional Annual Report and an adjustment to the rate case number to reflect the effective tax rate for the year.

All parties and the Administrative Law Judge concluded that these adjustments were proper and did not affect the calculation of test-year revenue requirements. The Commission concurs.

2) ***Replaced and Abandoned Infrastructure*—**How much of the Company's aging infrastructure scheduled to be replaced will be abandoned and how will that comply with existing regulations?

The Company addressed this issue in the direct, supplemental direct, and rebuttal testimony of Talmage R. Centers, P.E., explaining that it complies with the environmental and safety regulations of the federal Pipeline and Hazardous Materials Safety Administration and works closely with affected municipalities when replacing or abandoning infrastructure.

The Suburban Rate Authority addressed the issue in the direct and surrebuttal testimony of James Kosluchar, P.E. Mr. Kosluchar agreed that Company practices appear to be consistent with public safety and environmental remediation standards and that the Company works effectively with municipalities on replacement and abandonment projects. He emphasized the importance of continued, close cooperation.

The commenting parties and the Administrative Law Judge agreed that Company practices on infrastructure replacement and abandonment did not require further scrutiny at this time. The Commission concurs.

The Company detailed its accounting practices regarding replaced and abandoned infrastructure in the supplemental direct testimony of Kirk R. Nesvig. The parties and the Administrative Law Judge found that those practices did not require further scrutiny at this time, and the Commission concurs.

3) ***Corporate Hourly Billing Rate*—**How is the hourly billing rate for corporate services to CenterPoint Energy calculated?

The Company addressed this issue in the supplemental direct testimony of Kirk R. Nesvig, who explained that the hourly rate is determined annually, is based on planned expenditures divided by total billable hours, and is trued up to reflect any difference between projected and actual costs. The parties and the Administrative Law Judge concluded that the formula did not require further scrutiny at this time, and the Commission concurs.

4) ***Over-collection of 2008 Rate Case Costs*—**What is the status of the 2008 rate-case-costs tracker account?

This issue was fully addressed in the course of this rate case and is discussed below with the other contested issues.

5) ***Financial Impact of Aberrant Billing Periods*—**What is the financial impact to ratepayers of extended or shortened billing periods due to accelerated or delayed meter readings?

The Company addressed this issue in the supplementary direct testimony of Burl M. Drews, who testified that the financial impact on ratepayers of extended or shortened billing periods was not material. Some 99.72% of residential customers and 99.13% of small volume commercial and industrial customers received twelve monthly bills during the 2012 calendar year. The residential customer class as a body paid $932.77 less in fixed customer charges than if all customers had received twelve monthly bills, and the small volume commercial and industrial class as a body paid $488.67 more.

The parties and the Administrative Law Judge concluded that the financial impacts of extended or shortened billing periods did not require further scrutiny at this time, and the Commission concurs.

6) ***Pipeline Safety Filing Requirement*—**The Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing directed the Company to file any subsequent response to the warning letters and notices of probable violation issued by the Minnesota Office of Pipeline Safety in Case No. 1299473-1 (2011-2013) and No. 1307070-2 (2013).

The Company provided then-current information in the supplemental direct testimony of Talmadge R. Centers, P.E. On November 6, 2013, the Company filed copies of its final compliance documents in Case No. 1299473-1 (2011-2013) and the Office of Pipeline Safety's case closing letter in Case No. 1307070-2 (2013).

The parties and the Administrative Law Judge concluded that the filing requirement had been met and that further scrutiny was not indicated at this time. The Commission concurs.

7) ***Updated Sales Forecast Filing Requirement*—**The Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing directed the Company to file any updated sales forecasts from its general rate case in its per dekatherm demand cost of gas rate.

The Company filed updates to its base cost of gas on December 23, 2013 in both this case and its base cost of gas docket, G-008/MR-13-674. These updates were examined in both dockets.

8) ***Decoupling Analysis Filing Requirement*—**The Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing directed the Company to file an analysis and discussion of the potential impacts of various decoupling scenarios.

The Company filed the requested decoupling scenario analysis in the supplemental direct testimony of Paul Gastineau. This became a major issue and is discussed below.

FINANCIAL ISSUES

V. Qualified Pension Expense—Discount Rate

In its initial filing, the Company identified $6,300,000 in test year pension costs before allocation between regulated and non-regulated operations. The Company arrived at the figure based on the plan's asset value, the assumed long-term growth rate of the asset (also called the expected return on assets), and a discount rate used to adjust between the plan's present value and the amount needed to pay future benefits.

The lower the discount rate in the calculation, the higher the calculated pension expense; the higher the discount rate, the lower the calculated pension expense. The ALJ did not recommend the Company's proposed discount rate of 4.75%, and the Company took exception to the ALJ's recommended discount rate of 7.25%.

A. Positions of the Parties

1. The Company

The Company objected to the ALJ's discount rate recommendation. The Company argued that the ALJ's rationale and recommended rate were not supported by the record, and that the Commission should instead adopt the Company-proposed discount rate of 4.75%. It argued that the Company's discount rate proposal reflected the actuarial assumptions required by accounting standards. The Company also pointed to evidence in the record that discount rates vary from plan to plan, depending on the plan's demographics and benefit provisions.

2. The Department

The Department recommended setting the discount rate at 7.25% to match the plan's expected return on assets. The Department's position was that the pension expense calculation for ratemaking purposes did not need to be governed by accounting practices implemented for another purpose.

The Department argued that the discount rate proposed by the Company was lower than necessary, and that for ratemaking purposes it is not reasonable to use different rates for the discount rate and the expected return on assets over the same period of time. It contended that the Company was unlikely to experience the circumstances assumed in the Company's discount rate calculation, causing the calculation to produce an artificially low result.

B. The Recommendation of the Administrative Law Judge

The ALJ agreed with the Department that the Company did not demonstrate the reasonableness of its discount rate, particularly because it was significantly lower than the proposed expected long-term growth rate.

The ALJ recommended that the Commission calculate the Company's test year pension expense using 7.25% for both the long-term growth rate and the discount rate. The ALJ's recommendation was based in part on the Department's recommendation that the discount rate and the expected return on assets be set to the same figure for ratemaking purposes. The ALJ reasoned that setting the two rates to the same figure was consistent with the Commission's decision in the 2012 Xcel Energy rate case.[8]

C. Commission Action

The Commission will not adopt the ALJ's recommendation concerning the 7.25% discount rate. The Commission will instead adopt a discount rate of 5.35% for purposes of calculating the qualified pension expense.

The calculation of pension expenses requires actuarial assumptions appropriate to the factual circumstances in each case. The factual record that resulted in the discount rate determination in the Xcel rate case does not pertain to the pension expense calculation here.

The Commission agrees with the Department that neither the accounting standard nor the federal pension funding laws govern pension expense calculations for ratemaking purposes. When the facts and circumstances of a case support adopting a discount rate that differs from the discount rate dictated by accounting standards applied for other purposes, it is appropriate to adopt a rate that differs.

But even accepting the Department's argument that the Company's rate calculation is artificially low, the Company's evidence provides the best basis for establishing an appropriate rate. The Commission will therefore establish a discount rate with a basis in the record evidence. In this case, the Commission concludes that the Department's calculated historical five-year (2009 – 2013) average discount rate of 5.35% is appropriate.[9]

The appropriate discount rate continuously varies, but changes are only reflected in utility rates periodically—when a rate case is decided. The Company's proposed discount rate is markedly lower than average. For rate setting purposes, in this case, it is appropriate to use a historical average to buffer the effect the recently-below-average discount rate would have on the overall test-year pension expense. Under these conditions, a discount rate based on the five-year average is more reasonable than a discount rate determined at a single point in time, the timing governed by Company's choice to initiate a rate case.

VI. Non-Qualified Pension and Savings Plan Expense

A. Introduction

The Company requests recovery of $36,133 in non-qualified pension expense, and $3,490 in non-qualified savings plan expense. The Company offers these non-qualified plans to employees because qualified pension and defined contribution savings plan benefits are limited by IRS caps on annual earnings, benefit contributions, or benefits payable. Non-qualified plans supplement the pension and savings plans for high-earning employees subject to the IRS cap on those benefits. Non-qualified pension and savings plans do not receive the same tax-favored status as qualified plans.

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[8] *In re: the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Findings of Fact, Conclusions of Law, and Order at 7, Docket No. E-002/GR-12-961 (September 3, 2013).

[9] Direct Testimony of Mark A. Johnson at 13.

B. Positions of the Parties

The Department argued that the non-qualified pension and savings plan expenses should be excluded from the Company's test year. It asserted that these plans only benefit highly-compensated employees, and that the Company had not established that the identified expenses were necessary and reasonable.

The Company objected to the ALJ's decision to exclude the non-qualified pension expense. It argued that it had established that its overall compensation for all employees is reasonable, which includes the Company's compensation for employees who receive non-qualified pension benefits.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the Company had failed to demonstrate the reasonableness of these expenses. She recommended that the Commission reduce the Company's requested test-year expenses by $36,133 for the non-qualified pension expense, and by $3,490 for the non-qualified savings plan expense.

D. Commission Action

The Commission agrees with and will adopt the ALJ's findings and conclusions concerning the non-qualified pension and savings plan expenses. The ALJ recommended disallowing the expenses after concluding that the record lacked evidence adequate to establish that the expenses were reasonable and necessary costs of providing utility service.

The Commission agrees—because the Company did not establish that these expenses are reasonable and necessary to provide utility service it will disallow recovery of the expenses. While technically open to all employees, benefits under these plans only accrue to the Company's highest earners. The record lacks evidence that absent these benefits the Company could not secure employees necessary to provide safe, reliable service. The Commission will require the Company to adjust its rate base to remove any associated capitalized costs commensurate with the disallowance.

VII. Incentive Compensation

A. Introduction

The Company sought rate recovery of $2,214,765 in short-term incentive compensation costs and $258,094[10] in long-term incentive compensation costs. Incentive compensation is paid in addition to base pay and is contingent on the Company meeting specified financial or operational goals.

Short-term incentive compensation is available to all employees. It ranges in amount from 1.5% to 2% of base pay for bargaining unit employees up to much higher portions of base pay for high-level managers and executives. Payment amounts are determined by Company performance in the following categories:

[10] The Administrative Law Judge used a slightly lower and, as it turns out, erroneous number, $253,448. The parties agree that $258,094 is the proper number.

CenterPoint Energy Core Operating Income	25%
Gas Operations Core Operating Income	25%
Operations & Maintenance Expenditures	26%
Safety—Recordable Incident Rate	8%
Safety—Lost Time Incident Rate	8%
Preventable Vehicle Incident Rate	8%

Fifty percent of short-term incentive compensation is automatically owed when certain metrics are met; the other 50% is payable at the discretion of management. Short-term incentive compensation is paid in cash in a one-time annual payment.

Long-term incentive compensation is available only to executives and high-level managers. It ranges in amount from 10% upward, with higher percentages tied to higher base salaries and higher-level responsibilities. The stated purpose of the program is to align management activities with shareholder interests by encouraging sustained improvements in Company financial performance, as measured by total shareholder return, modified cash flow, operating income, and earnings per share. Long-term incentive compensation is paid in restricted stock units or performance shares or units.

In the Company's last rate case, the Commission disallowed rate recovery of long-term incentive compensation costs, capped recovery of short-term incentive compensation costs at 25% of base pay, and required the Company to track amounts paid to employees and refund to ratepayers all amounts built into rates and not paid to employees.

B. Positions of the Parties

1. The Company

The Company argued that both long- and short-term incentive compensation programs were standard in the utility industry, that they were necessary to attract and retain qualified employees for key leadership positions, and that they benefitted ratepayers by contributing to the strong financial performance required for a financially healthy operating utility. The Company opposed any cap on either incentive compensation plan, saying the plans' value to ratepayers justified including their full costs in rates.

The Company opposed establishing a tracker account for the refund of unpaid incentive compensation, claiming it would be unfair—because it would be asymmetrical—and inconsistent with fundamental ratemaking principles, which normally do not permit or require rate adjustments when actual costs differ from authorized test-year costs.

2. The Department

The Department recommended disallowing rate recovery of all long-term incentive compensation costs, capping recovery of short-term incentive compensation costs at 15% of base pay, and requiring the Company to track amounts paid to employees and refund to ratepayers all incentive compensation costs built into rates and not paid to employees.

The Department pointed out that the Commission has consistently taken a hard look at incentive compensation, usually disallowing rate recovery of long-term plans (because they target only shareholder goals) and capping rate recovery of short-term plans at 15%-25% of base pay (to avoid over-rewarding short-term thinking and reflect the plans' independent value to shareholders).

In this case, the Department recommended disallowing all rate recovery of the Company's long-term program, mainly because the Commission had disallowed all rate recovery in the Company's last rate case, finding as follows:

> Not only does the program's link operate almost exclusively to the benefit of shareholders instead of ratepayers - who would derive greater benefit from different performance metrics, such as service quality, safety, affordability, customer service - but the link carries the potential to encourage key decision-makers to focus on short-term financial performance to the detriment of the long-term planning uniquely critical to the mission of public utilities to provide safe, reliable, and affordable service over the very long term.
>
> Offering key decision-makers large financial rewards for producing short-term shareholder benefits does not promote regulatory efficiency, ratepayer interests, or the long-term fortunes of the Company. Since the public has an interest in ensuring the long-term viability and stability of the Company, this is a serious defect.[11]

The Department stated that the long-term plan had not been substantially changed since the last rate case and that it continued to be fair and reasonable for shareholders, not ratepayers, to bear its costs.

The Department analyzed the Company's short-term incentive compensation program and concluded that a 15% cap would represent the most appropriate balancing of ratepayer and shareholder interests, largely because 50% of the plan's payout terms were linked to meeting corporate financial goals, not direct ratepayer goals such as safety, affordability, and customer service.

Finally, the Department recommended establishing a tracker account to track and refund any incentive compensation amounts built into rates and not paid to employees, distinguishing these costs from typical test-year costs in that the Company retained absolute discretion over whether to incur at least 50% of them.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended disallowing rate recovery of all long-term incentive compensation costs, in large part because the Commission had disallowed them in the Company's last rate case, and the program was substantially the same. She concurred with the finding in the last rate case order that the program had the potential to cause management "to focus on short-term

[11] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order (January 11, 2010) at 44.

financial performance to the detriment of the long-term planning uniquely critical to the mission of public utilities to provide safe, reliable, and affordable service over the very long term."[12]

She concluded that the indirect benefits of the program to ratepayers were not sufficient to overcome that risk. She found that total disallowance was consistent with Commission action in other rate cases and that there was no evidence in the record showing that disallowance would jeopardize the Company's ability to attract and retain competent management.

She recommended permitting rate recovery of short-term incentive compensation costs, subject to a cap of 25% of base pay. She found the 25% cap reasonable in large part because the Commission had adopted it in the Company's last rate case. She also found that it would strike the right balance between the need to attract qualified employees and encourage high performance and the need to ensure that "short-term considerations do not overwhelm the long-term commitment essential to building a stable utility capable of providing safe and affordable service."[13]

Finally, the Administrative Law Judge recommended requiring the Company to track incentive compensation amounts paid to employees and to refund to ratepayers all amounts built into rates and not paid to employees, citing the Commission's decision in the Company's last rate case:

> Company management retains the right to amend, modify, suspend, or terminate its incentive compensation plans at any time for any reason. It would be unreasonable to permit the Company to profit financially from exercising that right. Similarly, it would be unreasonable to permit shareholders to receive a windfall in salary savings if employee performance targets are missed and significant amounts of incentive compensation go unpaid.[14]

D. Commission Action

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendations.

The Commission agrees that the Company's long-term incentive compensation program is substantially unchanged from the one rejected in the last rate case and that its costs should continue to be borne by shareholders. It is designed solely to serve shareholders' interests; its benefits to ratepayers are indirect and could be better served by other means; and its three-year horizon for rewarding corporate financial performance carries the potential to divert attention from the much longer planning horizons critical to providing safe, reliable, and affordable utility service.

The Commission also agrees with the Administrative Law Judge that short-term incentive compensation costs should continue to be recovered from ratepayers subject to a cap of 25% of base pay. That cap continues to strike the right balance between the interests of ratepayers and shareholders and between the goals of rewarding solid day-to-day financial management and protecting the long-term thinking vital to good utility management.

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[12] *Id.* at 43.

[13] *Id.* at 43 – 44.

[14] *Id.* at 44.

The cap responds appropriately to the design of the short-term program. While the program does tie employee compensation in part to performance goals that directly serve ratepayers—safety and operational efficiency—it also ties compensation to Company financial performance, and at the 50% level. While that financial performance metric is less troubling than the one in the long-term plan—since it measures financial performance in terms of overall income targets, not shareholder gains—it continues to provide direct benefits to shareholders and indirect benefits to ratepayers. For all these reasons, the Commission agrees with the ALJ that the 25% cap is appropriate and should remain in place.

Finally, the Commission concurs with the ALJ that the Company should continue to track all test-year incentive compensation amounts not actually paid out and refund them to ratepayers. These costs are not typical test-year costs and should not be treated as if they were: the Company has total discretion over whether to incur at least 50% of them. It would be inconsistent with test-year principles and unfair to ratepayers to authorize full and unconditional recovery of these contingent, discretionary costs.

VIII. Marketing Programs

A. Introduction

The Company proposed to include in test-year costs the costs of three marketing programs designed to encourage the use of natural gas over electricity. Those programs are the Residential Water Heater Program ($330,474), the Foodservice Program ($84,448), and the Commercial and Industrial Market Rebate Program ($50,963).

The Residential Water Heater Program provides rebates to builders to install natural gas water heaters in new homes instead of electric water heaters. Gas water heaters have higher installation costs (approximately $626 per unit), which act as a disincentive to builders, but lower operating costs, higher energy efficiency, and significant environmental benefits.

The Foodservice Program provides information about natural gas foodservice applications to commercial and institutional foodservice providers, such as hotels, schools, and hospitals. The program also provides rebates for installing natural gas equipment, such as booster water heaters, dishwashers, and steam cooking equipment. As with the water-heater program, the goal is to overcome the barrier of higher initial costs through rebates and education.

The Commercial and Industrial (C&I) Market Rebate Program provides C&I customers with information about gas-driven applications and rebates for installing equipment such as gas-driven engines, humidifiers, and desiccant equipment. As in the other two programs, the goal is to offset higher initial capital costs with lower operating costs and environmental benefits.

No one disputed that the programs are cost-effective, with a ten-year net present value after expenditures of $722,000. They have been granted rate recovery in the Company's last three rate cases.

B. Positions of the Parties

1. The OAG

The OAG opposed rate recovery of the costs of these programs on grounds that programs designed to increase natural gas use conflict with the policy goals of decoupling and with the Commission's statutory duty to set rates, to the maximum reasonable extent, to encourage energy conservation.[15]

2. The Company

The Company argued that the programs benefit customers, with or without a decoupling rate design, by reducing rates through more efficient use of its distribution system and lower per-unit prices. The Company emphasized that the program is not designed to increase energy usage overall, but to encourage customers to substitute higher-efficiency, lower-emissions natural gas for electricity. The Company argued that the program is therefore consistent with state conservation goals.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended permitting rate recovery of the programs' costs with or without a decoupling rate design. She found that they benefit all customers through lower rates and benefit participating customers through lower ongoing operating costs. She found that they are cost-effective, provide environmental benefits, and do not conflict with state or Company conservation goals.

D. Commission Action

The Commission concurs with the Administrative Law Judge's findings, conclusions, and recommendations. These programs benefit ratepayers in the ways she noted and do not conflict with the policy goals of the pilot decoupling program adopted in this case or with state conservation goals. Their costs continue to qualify for rate recovery.

IX. Income Taxes

A. Introduction

CenterPoint included an adjusted income tax expense in test-year costs. The adjustments made by the Company did three things: (1) reconciled tax expense to current tax rates; (2) recognized the impact of deferred federal and state income taxes; and (3) flowed through prior years' investment tax credits to the appropriate accounts based on adjusted test-year operating income.

B. Positions of the Parties

The OAG argued that income tax expense should be reduced by $95,543 to disallow rate recovery of taxes that would not have been due if all expenses incurred by the Company in the areas of post-retirement employee benefits, meals and entertainment, and lobbying expenses had been tax-deductible. The OAG contended that permitting rate recovery of these tax amounts would be

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[15] Minn. Stat. § 216B.03.

unfair to ratepayers and inconsistent with state and federal tax policy by, in effect, granting a tax deduction not permitted by law.

The Company argued that the tax code does not control rate recoverability, which depends on whether a cost is reasonable and necessary for the provision of utility service. Since these non-tax-deductible costs were authorized for rate recovery, the Company argued, there is no reason to exclude the tax liability resulting from their non-deductibility.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that permitting rate recovery of these income tax costs would not change the tax treatment of the underlying costs and would therefore not contravene state or federal tax policy.

She also found that the controlling question is whether the underlying costs are reasonable and necessary, not whether they are tax-deductible. If they are reasonable and necessary for the provision of utility service, they are rate recoverable, and there is no reason to adjust test-year income tax costs to reflect their non-deductibility.

D. Commission Action

The Commission concurs with the findings, conclusions, and recommendations of the Administrative Law Judge. These costs are rate-recoverable and there is therefore no reason to adjust test-year income tax expense to reflect their non-deductibility.

X. Inflation Rates

A. Introduction

To calculate its Operations and Maintenance (O&M) costs for its October 1, 2013 to September 30, 2014 test year, the Company began with its actual 2012 O&M costs, made 24 adjustments for known and measurable changes, and applied inflation factors to all costs affected by inflation.

The Company used three inflation factors: one for direct payroll costs (5.32%), based on actual union wage contracts; one for secondary payroll costs (3.96%), based on wages, payroll taxes, and employee benefit costs; and one for other costs (4.05%), consisting of the average annual change in the Producer Price Index, the Bureau of Labor Statistics' index measuring cost changes for manufacturers and wholesalers.

The Company has used this process in all recent rate cases. These inflation factors accounted for $3,600,000 in test-year costs.

B. Positions of the Parties

1. The OAG

The OAG challenged the Company's inflation factors and instead proposed an overall inflation factor of -0.87%, based on its review and comparison of Company O&M expenses from 2009 to 2012. The OAG reported that during that period the Company's O&M costs dropped by an average of 0.87% and that applying that rate of inflation to test-year costs would reduce them by some $3,400,000.

2. The Company

The Company stated that it used the same approach to developing its inflation factors in this case that it has used in its last several rate cases and that the Commission has consistently approved them.

The Company stated that, while the OAG excluded gas costs and Conservation Improvement Program (CIP) costs from the O&M costs on which it based its inflation calculation, it included other significant costs—such as bad debt, Gas Affordability Program costs, and regulated pension costs—that are equally unaffected by inflation. Removing these costs from the 2009-2012 O&M cost comparison results in test-year inflation costs very close to the Company's.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended adopting the inflation factors used by the Company, because the Commission had approved their underlying methodology in the Company's last rate case and others preceding it and because those factors were supported by the record.

She found that the OAG's analysis of the change in O&M costs between 2009 and 2012 did not reflect the actual inflation experienced by the Company during that period, because that analysis failed to exclude from the costs compared substantial costs—e.g., bad debt, Gas Affordability Program costs, and regulated pension costs—that are largely unaffected by inflation and vary in response to other factors, such as firm revenues, weather, or volume throughput.

D. Commission Action

The Commission concurs with the Administrative Law Judge's findings, conclusions, and recommendations. The Company's proposed inflation factors are sound, supported in the record, and consistent with longstanding practice. The alternative analysis proposed by the OAG did not reflect the actual inflation experienced by the Company during the time period analyzed and could not reasonably form the basis for an alternative inflation factor.

XI. Investor Relations

A. Introduction

The Company included in test-year costs $252,582 for Investor Relations and Investor Services, which it described as follows:

> Investor Relations and Investor Services enable effective communication between CenterPoint Energy, the financial community, and other constituencies and include several services, including: communication to investors and the financial community, transfer agent transactions, shareholder recordkeeping functions, and the Company's annual shareholder meeting. The Company's filings with the SEC reflect the Company's capital structure and are relied on by investors and credit rating agencies, along with other factors. A primary responsibility of the Investor

> Relations area is to manage the ongoing business relationships with credit rating agencies and institutional investors. Without the annual meeting of shareholders, transfer agent transactions, required SEC filings, record keeping and communications with investors and rating agencies, we would not have a primary source of equity investment and ratepayers clearly benefit from the cost incurred to keeping this essential source of capital available.[16]

B. Positions of the Parties

1. The Department

The Department recommended permitting rate recovery of $126,291, half the amount the Company requested. The Department stated that, although it had no doubt that many costs associated with Investor Relations and Investor Services were reasonable and benefitted ratepayers, there was not enough analysis, detail, or documentation in the record to support a determination on which costs those were.

The Department pointed out that the Company has the burden of proof to show that proposed rate changes are just and reasonable and that the Commission is required to resolve any doubt as to reasonableness in favor of the consumer.[17] Rather than deny recovery completely—when some level of investor-relations expense is clearly necessary for the provision of utility service—the Department recommended permitting rate recovery at the 50% level adopted as a proxy for reasonable investor-relations costs in the last Xcel rate case.[18]

The Department also recommended that the Company, in its next rate case filing, provide greater detail about these costs, breaking them down by cost center and FERC account, and explaining why each cost is reasonable, necessary, and consistent with ratepayers' interests.

2. The Company

The Company emphasized that it needed access to capital on competitive terms and stated that that access depended in part on high-quality relationships and communications with individual investors, institutional investors, shareholders, transfer agents, credit rating agencies, security analysts, and other members of the investment community. The Company claimed that all investor-relations costs for which it sought recovery contributed to these ends.

The Company objected that the Department had failed to identify the expenses it believed did not benefit ratepayers and had failed to adequately explain its reasons for reaching that conclusion. It argued that the Department's emphasis on determining whether specific costs were more beneficial to ratepayers or shareholders overlooked the substantial ratepayer benefits all these

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[16] CPE Initial Brief at 84.

[17] Minn. Stat. §§ 216B.16, subd. 4; 216B.03.

[18] *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. The issue is not specifically addressed in the Commission's final order, but the Administrative Law Judge's recommendation to authorize recovery of 50% of these costs is adopted and incorporated.

costs provide. And it claimed that the Department's position failed to give proper weight to Minn. Stat. § 216B.16, subd. 8 (c), which provides as follows:

> The commission shall not withhold approval of a rate because it makes an allowance for expenses incurred by the utility to disseminate information about corporate affairs to its owners.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company had failed to provide the detail and documentation required to support its claim to recover $252,582 in investor relations costs.

She concurred with the parties that the Company must incur investor relations costs at some level to maintain its ability to attract capital at reasonable rates. She agreed that reasonable costs directly necessary to accomplish this objective were recoverable from ratepayers. She concluded that, given the absence of record evidence that specific costs and cost totals met this standard, the most reasonable course was to adopt the proxy for reasonable investor-relations costs (50%) that the Commission had adopted in the last general rate case raising this issue.

She found that limiting rate recovery to half the amount requested would not be inconsistent with Minn. Stat. § 216B.16, subd. 8 (c), because that statute applied only to communications with shareholders, not with everyone in the investment community, and because it did not in any case relieve the Commission of its duty to examine claimed costs for reasonableness.

D. Commission Action

The Commission concurs with the findings, conclusions, and recommendations of the Administrative Law Judge. Clearly, some level of investor relations expense is necessary for the provision of utility service; equally clearly, the Company has the burden of proof to establish the nature, amount, and necessity of each expense claimed. This burden has not been met. In the absence of record evidence supporting rate recovery for specific costs or cost totals, it is reasonable to permit rate recovery of 50% of claimed costs as a proxy for fully supported investor-relations costs.

The Commission also concurs that Minn. Stat. § 216B.16, subd. 8 (c) does not change this analysis. As the Administrative Law Judge notes, that statute applies only to communications with shareholders—not with all members of the investment community, as the claimed costs do—nor does it eliminate the Commission's duty to examine all costs, including shareholder-communications costs, for prudence and reasonableness.

XII. Recognizing Increase in Reconnection Fee

A. Introduction

The Company and the Department agreed it was appropriate to raise the fee for reconnecting disconnected meters from $22.50 to $28.00; they also agreed that this increase would raise annual revenues by some $126,396.

Test-year revenues, on which final rates are based, did not include this increase, since the Company did not collect it during the interim rates period. (The interim rates increase did not apply to reconnection fees and similar miscellaneous, non-recurring charges.) The Company and the Department disagreed over whether the Other Revenues component of test-year revenues should be updated to reflect the additional $126,396.

B. Positions of the Parties

The Company argued that updating test-year revenues to reflect amounts not collected during the test year was inconsistent with the test-year concept on which the ratemaking process so heavily relies. The Department argued that it would be fundamentally unfair to wait until the end of the Company's next rate case to include in the revenues on which final rates are based this additional $126,396 in reconnection fees.

The Company also argued that if test-year revenues were updated to reflect the increase in reconnection fees, the interim rates refund should be reduced by the same amount to reflect that the Company did not collect that amount during the interim rates period. The Department originally recommended deferring that issue to the interim-rates refund filing, but acceded to the Administrative Law Judge's recommendation to accept the Company's position on that issue.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with the Department that it was appropriate to include in the final revenues on which final rates will be calculated this certain increase in revenues. She also concurred with the Company that it was reasonable to deduct from the interim rates refund the $126,396 authorized increase in reconnection fees that it did not collect during the interim rates period.

D. Commission Action

The Commission concurs with the Administrative Law Judge that there is no sound reason to exclude this known increase in revenue from the revenue on which final rates are calculated; test-year revenue must therefore be updated to reflect the $126,396 per year the Company will receive in reconnection fees once final rates are implemented.

The Commission also concurs with the Administrative Law Judge that it is reasonable to deduct this amount from the interim-rates refund to reflect the fact that the Company did not collect it during the interim rates period, even though it is part of the final revenue requirement.

XIII. 2008 Rate Case Expenses

A. Introduction

The Company filed its last rate case in 2008, which the Commission addressed in its January 11, 2010 Findings of Fact, Conclusions of Law, and Order.[19] In that order, the Commission decided the issue of recovery of expenses for the 2008 rate case. Specifically, the Commission approved 2008 rate case expenses for recovery and determined the appropriate amortization period for pro-rated expense inclusion in the Company's test year.

The Commission tries to set a cost-recovery or amortization period that will coincide with the time between rate cases. Setting the cost recovery period can be challenging, however, since individual

[19] Docket No. G-008/GR-08-1075, reconsideration denied March 18, 2010.

utilities, not the Commission, generally control the timing and frequency of rate case filings. Rate cases before this Commission have involved rate case intervals from two years to twenty years—and a two-year cost recovery assumption followed by a twenty-year rate case interval results in eighteen years of over-recovering rate case costs from ratepayers.

In the 2008 rate case, the Commission set a three-year amortization period to collect an authorized $1,490,736 in rate case expenses, and required the Company to track recoveries exceeding the authorized test-year expense.[20] Tracking excess recoveries could help protect ratepayers from over-collection in the event of a longer-than-expected interval between rate cases.

Because the time between rate cases was longer than the three-year amortization period, the Company collected $2,360,322 through the recovery allowed by the Commission's order. At issue is how much the Company must return to ratepayers.

B. Positions of the Parties

1. The Company

The Company argued that it should be able to recover the 2008 rate case expenses it actually incurred, which it stated equaled $1,929,900. The Company therefore proposed refunding $400,000, plus interest, to ratepayers. The Company argued that the interest rate on the over-collected amount should be set at the prime rate.

In its exceptions to the ALJ's Report, the Company also objected to the ALJ's recommended method of accomplishing the refund. The Company argued that an adjustment to the revenue requirement was inappropriate for a one-time refund, which would more appropriately be accomplished by refunding the over-collection along with any interim rate refund at the conclusion of this case.

2. The Department

The Department disputed the Company's interpretation of the Commission's 2010 order, and argued that the Company was limited by that order to collect only the authorized amount of $1,490,736. The Department asserted that the remaining $869,596 should be returned to ratepayers, with 21 months of interest calculated at the Company's 2008 authorized rate of return (8.09%).

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the Commission determined the authorized rate case recovery amount in its 2010 order, and recommended that the Company be required to credit the over-collected amount of $869,596 to its revenue requirement.

The ALJ also recommended that the Company pay interest on the over-collected amount at the Company's 2008 rate case rate of return (8.09%).

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[20] Id. at 41.

D. Commission Action

The Commission agrees with the ALJ and the Department that the Commission determined the authorized 2008 rate case expense in its January 11, 2010, order, and will not revisit the issue. The Company was authorized to recover $1,490,736 in 2008 rate case expenses, and the Commission directed that recovery be tracked to "protect[] ratepayers from over-collection and protect[] the Company from any need to bring an otherwise unnecessary rate case to vindicate its rate-case-interval estimate."[21] The Commission intended the tracking mechanism to address uncertainty about the appropriate amortization period, not uncertainty in the amount of the allowed expense.

The Commission determines that the amount of over-recovery of 2008 rate case expenses is the difference between the amount recovered during the 57-month tracking period ($2,360,332) and CenterPoint's approved expenses ($1,490,736), or $869,596.

The Commission also agrees with the Department and the ALJ that the appropriate interest rate to apply to the refunded amount is equal to the rate of return set in the Company's prior rate case: 8.09%. The Company had fully recovered its authorized rate case expenses at the end of 2011. The over-collected funds were collected over 21 months, and will have been retained for longer still, making an interest rate like the prime rate inadequate compensation to ratepayers for the use of their money.

The Commission concludes that the Company's last established rate of return, 8.09%, appropriately balances the interests of ratepayers, the utility, and the public. The rate of return reflects the Company's weighted-average cost to acquire capital, making it a suitable proxy for interest on amounts borrowed from ratepayers in circumstances like this—specifically: when amounts are over-collected from ratepayers for an extended time, the duration of which is largely in the Company's control, and when the prime rate would not reasonably compensate ratepayers. Returning funds to ratepayers at the rate of return most equitably compensates ratepayers for forgone opportunities had they not been compelled to lend money to the utility, without penalizing the Company relative to its average cost to obtain funds in the market.

Finally, the Commission agrees with the Company that returning the over-collected amount plus interest with the interim rate refund is the appropriate means to accomplish the refund. The Department also recommended this refund mechanism in its initial post-hearing brief to the ALJ. The Commission will therefore reject ALJ finding 794 and direct the Company to issue the refund with the interim rate refund.

XIV. Current Rate Case Expense, Amortization, and Recovery

A. Introduction

Reasonable, prudently incurred rate case expenses are properly included in test year costs and built into rates for recovery from ratepayers. The Commission tries to set the cost-recovery (or, amortization) period—which determines the percentage of total rate case costs built into rates on an annual basis—to coincide with the time period between rate cases. It is important for these two

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[21] Id.

time periods to match as closely as possible, to ensure that the utility recovers its authorized rate case costs without over-recovering them.

At issue are: whether the Company's proposed rate case expense amount is reasonable, what amortization period for recovery of the authorized expense is appropriate, and whether it is appropriate to protect ratepayers from over-collection of rate case expenses through a tracking mechanism.

B. Positions of the Parties

1. The Company

The Company initially proposed to recover $2,015,335 of current rate case expenses over a two-year amortization period, for a test-year rate case expense of $1,007,667. However, the Company did not object to the ALJ's recommendation to reduce the proposed expense by $100,000, an amount earmarked for intervenor compensation that was not used in this proceeding.

The Company supported its proposal for a two-year amortization period by arguing that it anticipated a period of increased expenses and capital investment, and accordingly would likely file its next rate case in no more than two years. The Company objected to the use of a rate case expense tracker mechanism that would allow ratepayers to be refunded for over-collected rate case expense amounts, but would not allow additional recovery of actual expenses beyond the amount for which it requested approval in this case.

2. The OAG

The OAG objected to certain components of the Company's proposed rate case expenses that it argued were unnecessary or overstated. The OAG argued that the rate case expense should be reduced by $150,000 that paid for expert testimony related to weather and climate the OAG believed to be of limited value; by $42,918 for expenses incurred for this case but prior to the test year; and by $200,000 for what the OAG asserted were excessive outside legal fees.

Overall, including the $100,000 of unused intervenor compensation funds, the OAG argued that the Company's rate case expense should be reduced by $492,918.

3. The Department

In its exceptions to the ALJ's report the Department did not object to the ALJ's recommendations on these issues. But in oral argument to the Commission, and in a May 7 letter detailing its recommended decision options, the Department stated its preferences concerning amortization in the alternative. The Department recommended that the Commission impose a four-year amortization period and no recovery tracker. However, if the Commission imposed a shorter period, the Department supported the recommendations of the ALJ concerning amortization, the recovery tracker, and the interest rate.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve the Company's identified rate case expenses—minus $100,000 in unused intervenor compensation funds.

The ALJ also considered the Company's preferred two-year amortization period, and found its anticipated timeline more appropriate than conclusions that could be drawn from historical practice. She concluded that "it is more likely than not that the Company will bring its next rate case sooner than it has on average," and recommended a two-year amortization period.

The ALJ also recommended a rate case expense tracker be implemented, specifying that the Commission should expressly require refunds to ratepayers for collections exceeding the amount approved, and for interest calculated at the Company's rate of return.

D. Commission Action

The Commission agrees with and adopts the ALJ's findings and recommendations on these issues. As detailed below, the Commission will approve a regulated rate-case expense amount of $2,015,335, minus $100,000, for an authorized regulated rate case expense amount of $1,915,335. The Commission will direct that recovery be amortized for a two-year recovery period, and that any over-recovery of the amount be tracked for refund in a future rate case.

1. Rate Case Expenses Approved

The Commission finds the ALJ's findings and recommendations on the disputed rate case expense items to be thorough and well-reasoned. The Commission agrees that the Company's weather- and climate-related testimony was relevant to the issues in this case, that the expenses incurred prior to the test year but for this rate case are proper to include in the recovery amount, and that the record does not support excluding any amount of outside legal fees. The Commission will reduce the proposed expenses by $100,000 because no intervenor compensation was paid in this case.

Accordingly, the Commission approves for recovery a regulated rate case expense amount of $1,915,335.

2. Rate Case Amortization and Tracker

The Commission also agrees with and adopts the ALJ's recommendations concerning the amortization period and recovery tracker. The Commission will require that the rate case expenses be amortized for recovery over two years, and that a Rate Case Expense Recovery tracker be implemented.

As the ALJ found, the evidence supports a conclusion that it is more likely than not that the Company will file its next rate case sooner than its historical average. Among other supporting factors, the Company plans to undertake significant capital investments at a rate that would plausibly motivate it to make more frequent rate case filings.

However, the ALJ was left with some uncertainty that the two-year prediction was firm. The ALJ noted that "the Company controls that decision." The ALJ believed it appropriate to protect ratepayers from "another situation where the Company chooses to wait to bring its next rate case" through a tracker-and-refund mechanism. The Commission agrees that under the circumstances in this case, a tracker is appropriate.

While a two-year period between rate cases is a reasonable prediction in this case, the Company may choose to wait longer than originally anticipated—as it did before filing this case. Additionally, certain of the Commission's decisions in this case may reduce financial pressure on the Company to adjust rates as often as initially predicted. The Commission concludes that there is adequate reason to protect ratepayers from a change in the Company's plans.

The Commission will therefore require the Company to implement a Rate Case Expense Recovery Tracker similar to the tracker in effect prior to this rate case. Ratepayers are entitled to a refund of all rate-case recoveries that exceed the approved rate case expense amount of $1,915,335.

The Commission also will require that an interest rate be applied to the refund of over-collections equal to the rate of return approved in this case (7.42%). The Commission concludes that this interest rate will reasonably compensate ratepayers for the use of their funds without penalizing the Company relative to its weighted average cost to obtain funds in the market, therefore minimizing any effect over-collecting these expenses might have on the Company's rate case timing decision.

The Commission has considered the Company's arguments concerning the asymmetry of the tracker—it will protect ratepayers from over-collection, but does not provide an opportunity for the Company to increase the amount of its recovery. The Company has had an opportunity in this case to fully litigate its rate case expenses and have them reviewed and approved for rate recovery. The tracking mechanism addresses uncertainty related to the amortization period for the rate case expense, and not uncertainty about the amount of the expense to be collected. For this reason, the Commission believes the tracker and refund provisions to be appropriate for the circumstances.

XV. Sales Forecast and Weather Normalization

A. Introduction

The Company's test year in this case is a projected test year that runs from October 2013 to September 2014. An accurate sales forecast for the test year is critical to calculating the Company's revenue requirement. An inaccurate sales forecast could result in rates that are either unreasonably high or unreasonably low, producing a windfall or possible financial harm to the Company.

Full decoupling increases the significance of sales forecast accuracy for ratepayers. Divergence between actual sales and forecasted sales would result in over- or under-collection that will be tracked and annually rectified through a refund or a surcharge over the course of the following year. A more accurate sales forecast reduces the likelihood and magnitude of decoupling-related rate adjustments.

Weather has a substantial effect on sales to residential, commercial, and some industrial customers. The Company proposed forecasting sales normalized with respect to a 10-year weather average. Weather normalization adjusts the test year sales forecast to reflect "normal" weather conditions by relying on historical weather data. The OAG disputed the data set used to weather normalize the forecasted test year.

B. Positions of the Parties

The OAG objected to the Company's use of 10-year historical weather data to weather-normalize the sales forecast. It argued that the Commission has used a 20-year time period in prior rate cases and should do so again in this case. The OAG stated that a 10-year historical average is more volatile, and more likely to be affected by historically anomalous weather. It also argued that using

10-year instead of 20-year data results in higher rates because the most recent 10 years have been warmer, reducing forecasted sales. The OAG recommended the Commission institute a generic, industry-wide proceeding to consider a wide range of weather normalization periods.

The Company and the Department agree that in this case, the 10-year historical data has superior predictive power and should be used as the basis for weather normalization of the sales forecast.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve the 10-year historical average data, stating that it "provides the most accurate prediction of weather for this utility at this time in this location." She further recommended that the Commission require the Company to continue to provide detailed information supporting its weather averaging methodology in future rate cases.

D. Commission Action

The Commission agrees with and will adopt the ALJ's recommendation to approve the Company's sales forecast. The Commission concludes that in this case and on this record, the Company's decision to use 10-year weather normalization data is appropriate. As supported by the Company's extensive testimony, and the Department's additional analysis, recent years have trended consistently warmer; consequently, longer-term averages' bias toward colder conditions reduces their predictive value relative to the 10-year average proposed by the Company.[22] In this case, the superior predictive value of the 10-year normalization period outweighs the concern that fewer data points increases the vulnerability of the average to outliers.

But approval of a forecast normalized using a 10-year weather history does not reflect the Commission's unequivocal support for the practice. Averages based on fewer data points are more susceptible to volatility, and are reasonably approached with skepticism. The Commission is simply persuaded, as were the Department and the ALJ, that this record establishes for this sales forecast that the 10-year weather data has superior predictive power to the alternative models considered by the parties. Because the Commission agrees with the ALJ's finding that appropriate weather normalization practices are best determined on a case-by-case basis, the Commission will not require an industry-wide investigation of weather normalization practices at this time.

However, the Commission will require that the Company provide in its next rate case, and in consultation with the Department, a comprehensive examination of the predictive power, volatility, and impact on the test year and future revenues of using 10, 15, and 20-year weather data in its sales forecast. This builds on the ALJ's recommendation that the Company be required to provide detailed data supporting its weather normalizing methodology. The information will aid the Commission in evaluating the relative merits and impacts of historical weather data on sales forecasts and on rates going forward.

CenterPoint, the Department, and the ALJ agreed that the Company's test year customer count, forecasting methodology, and pre-curtailment sales estimates are reasonable. They also agreed on a Department-proposed alternative curtailment methodology, and the Company agreed to provide further information on curtailments in future rate cases. The Commission concurs, and will adopt

[22] See Direct Testimony of Larry W. Loos at 14 – 15, stating that the data suggest a "persistent" underlying trend.

the Department's recommendation, with which the Company has agreed, to require the Company to provide additional information on curtailments and forecasted curtailment methodology in its next rate case.

Cost of Capital Issues

XVI. Return on Equity

A. Introduction

In setting just and reasonable rates, the Commission is required to "give due consideration . . . 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*."[23]

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances the utility infrastructure. The Commission must set rates at a level that permits stockholders to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

In short, the Commission must determine a reasonable cost of equity and factor that cost into rates. It would normally begin by examining the price of the utility's stock, but CenterPoint Energy Minnesota Gas is a division of CenterPoint Energy Resources Corporation and has no publicly traded common stock. Its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred from market data for companies that present similar investment risks.

The three parties who conducted full cost-of-equity studies—the Company, the Department, and the OAG—based their analysis on comparison groups of utilities they considered similar enough to CenterPoint to serve as proxies in determining the Company's cost of equity. The Company's comparison group contained nine proxy companies; the Department's contained eight, and the OAG's seven. While the three comparison groups were not quite identical, all three groups contained six of the same proxy companies and no group included any proxy company not in at least one other group. Consequently, the most significant differences between the parties' analyses and outcomes did not result from differences in their comparison groups, but from other philosophical and methodological differences.

All three parties conducted comprehensive analyses of the cost of equity, using both the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance, and the Capital Asset Pricing Model (CAPM), which the Commission has historically used as a secondary, corroborating resource. The Company also conducted a third analysis using the Risk Premium (RP) model, which the Commission has historically relied on less heavily, since the model has at times produced 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

[23] Minn. Stat. § 216B.16, subd. 6, emphasis added.

formula used by investors to assess the attractiveness of investment opportunities. It uses three inputs: dividends, market equity prices, and growth rates.

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

The RP Model determines the cost of equity by adding to current corporate bond yields a premium reflecting the greater returns realized (and presumably required) by equity holders over various historical periods.

B. Positions of the Parties

Although all three parties used the DCF and CAPM analytical models (with the Company using a third, the Risk Premium Model, as well), their results differed. This was true both because they used different iterations—in addition to the classic iteration—of the models, and because they all proposed adjustments to the results of their models to reflect other factors bearing on the Company's cost of equity.

The Company proposed upward adjustments to the cost of equity to take into account (a) the Company's small size, relative to the sizes of the individual proxy companies; (b) the relative weakness of its revenue-stabilization mechanisms, compared to those of the proxy companies; and (c) the costs of issuing securities (flotation costs), which the Company argued were not captured in the cost-of-equity models.

Of these additional, allegedly cost-escalating factors, the Department supported only one: flotation costs. The OAG supported none, but cited three additional factors that it argued reduced the cost of equity: (a) a more favorable economic climate in the state of Minnesota than the states in which the proxy companies operate; (b) a more favorable economic climate in the operating area of CenterPoint's parent company than the comparable operating areas of the proxy companies; and (c) the consistent excess of market value over book value for Company assets, due to regulatory accounting principles.

The Company's proposed cost of equity was 10.20%; the Department's was 9.59%; the OAG's was 8.73%.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge examined the parties' evidence and arguments in detail. She examined their analytical models—including inputs and implementation—for accuracy, credibility, and probative value. She ultimately recommended adopting the Department's proposed 9.59% return on equity.

She concluded that that number had been reached through the proper application of analytical models the Commission has found trustworthy in the past. She found that—under the facts of this case and on this record—the Department's modeling and inputs had solid record support and were consistent with the Company's right to receive a fair and reasonable return on its investment, the

Company's need to attract capital at competitive rates, and the Commission's duty to resolve any doubt as to reasonableness in favor of the consumer.[24]

D. Commission Action

The Commission concurs with the Administrative Law Judge's closely reasoned findings, conclusions, and recommendations on rate of return on equity. The Commission agrees that the Department's modeling, assumptions, and analysis were reasonable, transparent, supported by substantial evidence in the record, and consistent with historical Commission practice.

The Commission will set the cost of equity for CenterPoint at 9.59%.

XVII. Capital Structure and Overall Cost of Capital

The Company and the Department agreed on the Company's capital structure and on the cost of long- and short-term debt. The Administrative Law Judge concurred in their joint recommendation, as does the Commission.

The Company, the Department, and the OAG disagreed on the cost of common equity. As explained above, the Commission has set the cost of equity at 9.59%, as recommended by the Department and the Administrative Law Judge.

The resulting overall capital structure and cost of capital are set forth below:

Component	Component Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	40.16	5.84	2.35%
Short-Term Debt	07.24	0.36	0.03%
Common Equity	52.60	9.59	5.04%
Total	100.00%		7.42%

CLASS COST OF SERVICE STUDY ISSUES

XVIII. Class Cost of Service Study

A. Background

As required by rule, the Company's rate-case filing included a class cost of service study.[25]

The purpose of a class cost of service study is to determine, as accurately as possible, the costs of serving each customer class. While these costs cannot be determined with precision, it is critical that the cost study make both its underlying assumptions and the cost figures they yield as accurate and transparent as possible, because the Commission puts substantial weight on cost causation in determining what portion of the total revenue requirement each customer class should pay.

Parties challenged three aspects of the Company's cost study: (1) its compliance with the requirement in the Company's last rate case order that it allocate income taxes on the basis of the taxable income

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[24] Minn. Stat. § 216B.03.

[25] Minn. R. 7825.4300 C.

attributable to each class, not rate base; (2) its use of two-inch pipe—as opposed to one- or zero-inch pipe, in its minimum system study; and (3) its inter-class allocations of costs relating to sales, account maintenance, customer service and information, and regulatory compliance.

Each challenge is addressed below, followed by the Commission's determination that the class cost of service study is acceptable for use as a ratemaking tool in this case.

B. CCOSS Allocation of Income Taxes

1. Introduction

In the Company's last rate-case order, the Commission required the Company to change the way it allocated income tax expense among the customer classes:

> . . . . [T]o improve precision, future class cost of service studies must allocate income taxes on the basis of the taxable income attributable to each customer class, not on the basis of rate base. Not only is this allocation more logical—income taxes are causally linked to income, not capital investment—but it avoids embedding policy judgments in the class cost of service study, which is intended to function, as far as possible, as a policy-neutral empirical resource. Judgments based on fairness and equity are more properly made overtly as the rate design decisions they are.[26]

The Company reported that it ran into practical difficulties in implementing this directive, because basing inter-class income tax allocations on taxable income attributable to the revenues collected from each customer class necessarily incorporated the rate-design judgments built into the rates that generated those revenues—the situation the directive was designed to avoid. The Company dealt with the issue by filing two versions of its class cost of service study (CCOSS), CCOSS1 and CCOSS2.

In brief, CCOSS1 allocated income tax expense by separating total income tax expense into two parts: income tax expense on revenues generated under current rates and income tax expense on revenues that would be generated under the amount of the proposed rate increase. It then allocated the first tax amount based on each class's contribution to operating income (pre-tax, minus interest) and the second tax amount based on the percentage of rate base costs attributed to each class under the class cost of service study.

CCOSS2 allocated income tax expense by combining both income tax amounts and allocating the total amount based on the percentage of the rate base costs attributed to each class under the class cost of service study.

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[26] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order (January 11, 2010) at 55.

2. Positions of the Parties

a. The OAG

The OAG argued that CCOSS1 complied with the Commission's order in the last rate case and that CCOSS2 did not. The OAG argued that the Commission directive to "allocate income taxes on the basis of the taxable income attributable to each customer class, not on the basis of rate base" must be given its literal meaning and that cost-causation determinations made in regard to rate base cannot be used to determine cost causation in regard to income tax.

b. The Company and the Department

The Company and the Department argued that CCOSS2 was more accurate than CCOSS1 in determining cost causation for income tax expense and should be used for setting rates in this case.

They stated that basing cost responsibility on the actual operating revenues generated by each customer class necessarily meant incorporating the rate-design decisions built into the rates generating those revenues. They pointed out that those rate design decisions would include non-cost factors—e.g., ease of understanding, administrative efficiency, ability to pay, ability to deflect or pass on costs, conservation goals—and argued that non-cost factors should play no role in a class cost of service study.

They agreed that the income tax allocations of CCOSS2 were equivalent to the income tax allocations that would result from allocating income tax based on taxable income that reflected the cost of providing service. They also noted that in two recent rate cases the Commission set rates based on class cost of service studies using the income tax allocation method used in CCOSS2.[27]

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that CCOSS2 better addressed the substance of the directive in the Commission's last rate case order and should be used in setting rates in this case.

While she concurred with the OAG that CCOSS1 met the literal requirements of that directive, she found that the best reading of the order was that income tax expense should not be allocated on the basis of capital investments but on the basis of actual cost causation. She noted that the order was explicit on the need to avoid "embedding policy judgments in the class cost of service study, which is intended to function, as far as possible, as a policy-neutral empirical resource."

She found that basing income tax expense on revenues collected from customer classes necessarily incorporated the policy judgments on which rates were based, embedding those judgments in the class cost of service study. She also found that the Company and the Department had "demonstrated that, in this case, the allocation of income taxes by class under CCOSS2 is equal to

[27] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-10-971, Findings of Fact, Conclusions, and Order (May 14, 2012); *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-07,011/GR-10-977, Findings of Fact, Conclusions, and Order (July 13, 2012).

the apportionment that follows from using the 'taxable income that reflects the cost of providing service.'"[28]

4. Commission Action

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendation.

While CCOSS1 does allocate income tax expense on the basis of taxable income generated under current rates attributable to each customer class, not on the basis of rate base, its reliance on current rates necessarily departs from cost-causation principles and incorporates the policy judgments the Commission made in setting current rates. Policy judgments do not belong in the class cost of service study, but in the rate design decisions made in the course of the rate case.

The Commission agrees with the Administrative Law Judge that, counterintuitive as it first appears, using inter-class rate base cost allocations to allocate income tax expense is the most accurate method for allocating income tax-expense developed in this record, and it should be used in the Company's class cost of service study. The Commission therefore accepts the CCOSS2 method of allocating income tax expenses.

C. Minimum System Study

1. Introduction

An important purpose of the class cost of service study is to split the costs of the Company's distribution system—consisting primarily of its gas mains and the surface equipment used to monitor and regulate gas pressure at fixed locations—into two parts: the costs of connecting all customers to the central distribution network (customer costs) and the costs of delivering gas to customers (capacity costs).

The distinction has important rate consequences, because customer costs are allocated by class based on total customer numbers, and capacity costs are allocated by class based on total class usage. Since some 91% of CenterPoint customers are in the residential class, that class pays 91.25% of customer costs. Because their per-customer usage is lower than the per-customer usage of large customers, however, they pay only 60.25% of capacity costs.

To determine the appropriate split between customer costs and capacity costs, the Company conducted a "minimum system study," a study designed to determine the costs caused by simply connecting all customers to the system, assuming they would use no gas. These costs were classified as customer costs. All costs above these connection-only costs were assumed to be caused by the ability to deliver gas and were classified as capacity costs.

In constructing its minimum system, the Company assumed the use of a two-inch main, the same main it has used in all previous rate cases. The Company stated that it chose the two-inch main as the minimum practical size for connecting all customers to the system based on two characteristics: (1) the two-inch main has no significant, determinable capacity; and (2) the two-inch main is broadly representative of the mains in its system and in its Mains account, which

[28] ALJ's Report, Finding 522.

includes mains of many sizes and vintages, installed from the late 1800's to the present, under widely divergent physical and economic conditions.

2. Positions of the Parties

a. The OAG

The OAG challenged the Company's use of the two-inch main, claiming a one-inch main better met the minimum-practical-size requirement and that the use of the two-inch main shifted costs more appropriately classified as capacity costs to the residential class as customer costs. The OAG pointed out that one-inch mains have been installed throughout the Company's system for decades, through varying historical and economic periods, and are an integral part of the distribution system. The OAG claimed that, since the capacity quotient of a one-inch main is lower than that of a two-inch main, it more effectively meets the goal of identifying the costs of connection only, not delivery.

The OAG emphasized that the purpose of the minimum system study is theoretical—it is to construct a minimum system capable of connecting every customer, not to replicate the Company's actual system. The OAG argued that the study's use of the Company's most prevalent main, the two-inch main, indicated that that theoretical purpose was not being served.

The OAG testified that the use of two-inch mains is not universally accepted—the Company uses one-inch mains in its minimum system study in one of the jurisdictions in which it operates, and two of the three largest natural gas utilities in Minnesota, MERC and Xcel, use a zero-intercept methodology and the weighted average of mains two inches and under, respectively.[29]

b. The Company

The Company argued that the two-inch main was the main of the smallest practical size for connecting all customers to the central distribution system, without delivering gas. It argued that the main had essentially no capacity for delivering gas, citing a study demonstrating that in three housing subdivisions studied, the two-inch system could provide the required gas pressure to only 4%, 6%, and 11% of the locations the Company was required to serve.

The Company stated that the two-inch main was more representative of its current and historical infrastructure than the one-inch main, constituting 52.48% of the Mains account in linear footage and 29.44% in cost, appearing in more counties than the one-inch main, and falling closer to system averages in years in service.

The Company emphasized that it has consistently used the two-inch main in past minimum system studies in Minnesota rate cases and that it uses the two-inch main in minimum system studies in 15 of the 16 jurisdictions in which it operates.

3. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that it was reasonable for the Company to choose the two-inch main for use in the minimum system study in this case and that it had successfully used

[29] Ex. 407 (Nelson Direct) at 16-17.

the two-inch main in previous Minnesota rate cases and 15 of the 16 state jurisdictions in which it operates.

She found that the Company had demonstrated that the two-inch main had essentially no capacity and was therefore an appropriate size for use in a minimum system study. She rejected the OAG's claims that the one-inch main met the lowest-practical-size requirement equally well, finding that the decision of the Arkansas Commission cited by the OAG in support of this proposition was not in the mainstream.

She found that it was reasonable and fair for the class cost of service study to assign the costs of connection—as opposed to gas delivery—to all customers, without regard to usage, since all customers benefit from the Company standing ready to provide service, needed or not.

4. Commission Action

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendations on this issue. The Commission concurs that the Company has demonstrated on this record that its use of the two-inch main in its minimum system study is reasonable. Further, it has demonstrated that the use of the two-inch main is consistent with past Company practice and with the weight of regulatory authority in the jurisdictions in which it operates.

The Commission will, however, require further exploration of this issue in the Company's next rate case, in which it will be required to file a minimum system study based on a one-inch and a zero-inch pipe, in addition to the two-inch pipe it has traditionally used.

D. CCOSS Treatment of Sales Expense, FERC Accounts 911-916

1. Introduction and Positions of the Parties

The Company's class cost of service study allocated sales expense by number of customer locations in each customer class.

The Company argued that sales are made to all customers, and it is therefore appropriate to charge all customers equally for sales-related costs. The Company pointed out that the NARUC Gas Distribution Rate Design Manual (Gas Manual) accepts this method of cost allocation.[30]

The OAG and the Department challenged this allocation as unreasonable, arguing that it is highly unlikely that the Company spends equal amounts of time and money on sales activities directed toward every customer. They recommended allocating these costs on the basis of actual data, where available, and otherwise on the basis of each class's overall revenue responsibility.

These parties also noted that NARUC manuals are regulatory resources, not binding authority; that the Gas Manual notes that permitting recovery of sales expense is controversial, in light of conservation policies; and that NARUC's January 1992 Electric Manual states that sales expenses are general in nature and should be assigned on the basis of actual data on cost causation or, where data are unavailable, on the basis of the overall revenue responsibility of each class.

[30] NARUC is the National Association of Regulatory Utility Commissioners.

2. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with the Department and the OAG that the record demonstrated that it was more reasonable to allocate sales costs on the basis of actual data or, failing that, overall revenue responsibility, than customer locations. She found the guidance of the NARUC Electric Manual to be sound and persuasive.

3. Commission Action

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendations. The Company did not demonstrate that it targets its sales activities at every customer equally, and these general expenses should therefore be allocated generally, in the absence of actual data on cost causation.

E. CCOSS Treatment of Customer Accounts Expense, FERC Accounts 901-905

1. Introduction and Positions of the Parties

The Company has five accounts devoted to customer account expenses: 901—Supervision; 902—Meter Reading; 903—Customer Records and Collection Expense; 904—Uncollectible Accounts; and 905—Miscellaneous Customer Account Expenses.

The Company allocated all customer account expenses except Customer Records and Collection Expense (Account 903) by number of customer locations. The Company allocated the costs in that account by investment-weighted number of customer locations, because its experience showed that these costs could be higher for commercial and industrial customers, commensurate with the higher investment required to serve them.

The OAG challenged these cost allocations, arguing that the costs in all five accounts were higher for high-usage customers and should be allocated by investment-weighted number of customer locations. The OAG pointed to Company data on meter-reading costs—which it interpreted as showing higher costs for high-usage customers—as evidence that the costs in these accounts varied between customer classes, with higher-usage customers imposing higher costs. The OAG claimed that these costs were therefore more properly allocated by investment-weighted customer locations.

The Company did not interpret its meter-reading data to show higher costs for higher-usage customers and pointed out that its allocations were essentially consistent with the NARUC Gas Manual. The exception was the meter reading account, which the Gas Manual recommended allocating by meter count. The Company pointed out that, while meter count is somewhat different from number of customer locations, it is very different from the investment-weighted customer locations recommended by the OAG.

2. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with the Company that it had properly allocated these accounts. She found that the Company's allocations were consistent with past practice and generally consistent with the NARUC Gas Manual.

She found that the Company's allocation of FERC Account 902, Meter Reading, was inconsistent with the NARUC Gas Manual but was reasonable and supported in the record. She found that the Company's meter-reading data were not interpretable on their own, but that its testimony that costs did not differ with meter size was credible, given the absence of evidence linking cost to meter size and given the Company's familiarity with the data and its own operations.

3. Commission Action

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendations. The Company's cost allocations are reasonable and supported by substantial evidence in the record.

F. CCOSS Treatment of Customer Service and Informational Expense, FERC Accounts 907, 909, 910

1. Introduction and Positions of the Parties

The Company has three accounts devoted to customer service and informational expenses: FERC Accounts 907,909, and 910. The Company allocated all customer service and informational expense by number of customer locations.

The OAG challenged these allocations, claiming that large customers have more complex service issues and infrastructure and require more time and attention from the Company. The Company testified that it saw no connection between customer usage and the time and attention customers required. It also pointed out that the NARUC Gas Manual supported allocating these costs by customer locations.

2. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company's allocation of these costs by number of customer locations was reasonable and supported in the record. She found that that there was no record evidence that large customers required more customer service and information than small customers, and that there was record evidence, in the form of the Company's testimony, that they did not.

She found it was not self-evident that large customers would require more customer service than small ones, noting that some large, sophisticated customers might require little customer service and information. She found that the NARUC Gas Manual's approval of the Company's allocation method was not dispositive, but was an indication of reasonableness.

For all these reasons, she concluded that the Company's allocation of these costs was reasonable and should be approved.

3. Commission Action

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendation. The Company's allocations are reasonable and supported by substantial evidence in the record.

G. CCOSS Treatment of Regulatory Commission Expense, FERC Account 928

1. Introduction and Positions of the Parties

The Company has one account devoted to regulatory commission expense, FERC Account 928. The Company allocated all regulatory commission expense by number of customer locations.

The Department challenged this allocation, claiming that these costs are general, are not directly customer-related, do not vary by number of customers in a class, and should be allocated using a very general allocator, Total Production & Distribution O&M Expense less Gas Cost.

The Department argued that rate cases and other regulatory proceedings evaluate all types of costs and that there is no evidence that all customers cause the Company to incur regulatory costs in equal proportions. The Department stated that there is also no evidence that regulatory costs pertain more to a class with many customers with low individual usage than to a class with fewer customers and high individual usage. The Department pointed out that the NARUC Gas Manual recommends allocating regulatory commission costs based on Total Production & Distribution O&M Expense less Gas Cost.

The Company argued that it has used the customer-location allocator in its last three rate cases and that the Gas Manual is merely advisory. The Company also argued that it incurs regulatory expenses on behalf of all customers and that the Commission's broad public-interest mission encompasses all customer classes.

2. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with the Department's arguments and recommended allocating regulatory commission expense on the basis of Total Production & Distribution O&M Expense less Gas Cost.

She found that when the evidence suggests, as it does here, that a different allocator is more reasonable than one used in the past, past practice alone cannot refute that evidence. She agreed that the Company had not provided reasoning or evidence to support continuing to allocate regulatory commission expenses based on number of customer locations.

3. Commission Action

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendation. Regulatory commission costs are general, are not directly customer-related, are not linked to the number of customers in a class, and should be allocated as she recommends.

H. CCOSS Accepted; Requirements Set for Next Rate Case

With the modifications made above, the Commission accepts the Company's class cost of service study for use as a ratemaking tool in this case.

The Commission also accepts the recommendation of the Administrative Law Judge to continue to require the Company to explain and justify its classification and allocation methods when it files its class cost of service study in its next rate case. In the Company's last rate case, the Commission required as follows:

> Second, to improve transparency, the Commission will require that future class cost of service studies include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered by the Company. While these explanations may be based on the Gas Distribution Rate Design Manual of the National Association of Regulatory Utility Commissioners, they should also be based on the Company's specific system requirements, its experience, and its engineering and operating characteristics.[31]

This requirement remains valid and helpful. Cost classifications and allocations play a central role in ratemaking, and it is critical that the facts, assumptions, and theories on which they are based be as precise and transparent as possible. The Commission also concurs with the Administrative Law Judge that it would be helpful to add a requirement that the Company explain its reasoning in cases in which it did not consider alternative methods of allocation or classification, and the Commission will so require.

RATE DESIGN ISSUES

XIX. Inter-Class Revenue Apportionment

A. Introduction

In every rate case the new revenue requirement must be apportioned among the customer classes, raising the issue of whether to adjust the inter-class revenue responsibility built into the existing rate structure. In this case the Company and the Department proposed to fine-tune existing inter-class revenue allocations by shifting slightly more revenue responsibility to the customer classes (residential and commercial/industrial class A) whose rates do not recover costs as calculated under the Company's class cost of service study.

These two parties recommended adjusting the revenue responsibilities of the residential and commercial/industrial A (C&I A) classes to the point that they would be paying, respectively, 88.2% and 80.9% of the costs of serving them.[32] This recommendation translates into a 6.8% rate increase for each class, compared with the 5% overall rate increase requested by the Company.

[31] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order (January 11, 2010) at 55.

[32] These figures were developed by the Department based on the Company's class cost of service study. Direct Testimony of Christopher J. Shaw at 24 (November 26, 2013).

B. Positions of the Parties

1. The Company and the Department

The Company argued that, even under its proposal, these classes would pay less than the cost of service and that failing to adjust their revenue allocation percentages would increase the level of subsidization built into their rates. The Company argued that the proposed increase would not unduly burden either customer class.

The Department stated that it had carefully weighed both cost and non-cost factors, including fairness, ability to pay, avoiding rate shock, and sending appropriate price signals; it had concluded it was appropriate, under the facts of this case, to move residential and C&I A rates closer to cost by the amount recommended.

2. The OAG

The OAG opposed changing existing inter-class revenue allocations and recommended that the rate increase be allocated to all customers on an equal-percentage basis.

The OAG argued that the class cost of service study is based on numerous subjective judgments, provides at best a rough estimate of the cost of service, and should not be used for inter-class revenue allocation purposes. The OAG also claimed that revenue allocations to the interruptible classes do not reflect their value of service and that the possibility of raising their allocations to mirror those of the firm classes was not adequately explored.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the revenue allocation recommended by the Company and the Department appropriately balanced cost and non-cost factors and should be approved. She concurred with those parties that moving residential and C&I A rates closer to cost was an appropriate goal, which would not be advanced by the across-the-board rate increase proposed by the OAG.

D. Commission Action

The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendation on this issue. Under the facts of this case, shifting a slightly larger share of the revenue requirement to the residential and C&I A classes is reasonable and supported by substantial evidence.

XX. Revenue Allocation Filings in Next Rate Case

For greater clarity and ease of analysis, the Commission will require that in its next rate case CenterPoint make an additional filing on the costs of serving Individual Curtailment and Competitive Circumstances (ICCC) customers and that it revise the format of the public summary schedules on the allocation of each class's revenue responsibility.

A. Revenue Allocation of the ICCC Class

Individual Curtailment and Competitive Circumstances (ICCC) customers are a subset of the Small Volume Dual Fuel class; these customers pay a premium to limit the circumstances under which they can be curtailed, while still receiving the discount applicable to interruptible service. Since none of these customers have been curtailed in the past ten years, the Department expressed concern that their cost allocations might not reflect the full cost of providing what appears to be close to firm service.

The Department conducted an analysis of their cost of service, which showed that ICCC rates exceeded the cost of service, complied with applicable tariffs, and therefore did not require immediate adjustment. To ensure that this service is fairly priced, however, the Department recommended requiring the Company, in its next rate case, to file an analysis addressing (1) the reasonableness of allocating capacity-related costs to this class of customers; (2) each capacity-related cost that is avoided by the ICCC customers taking interruptible service; and (3) each capacity-related charge that would be incurred if an ICCC customer switched to firm service.

The Administrative Law Judge concurred in this recommendation. The Commission concurs and will so require.

B. Presenting Inter-Class Revenue Allocation Data

In this rate case filing the Company frequently combined smaller customer classes into one class when reporting rate design and revenue allocation information. Particularly, the Large Volume Firm, Dual Fuel Sales, and Large Volume Transportation classes were often combined, as were the Small Volume Dual Fuel Sales Service and Small Volume Dual Fuel Transportation Service classes.

To ensure accuracy and clarity, it is important that each customer class listed in the Company's tariffs be identified and treated separately, and the Commission will require this in the Company's next rate case.

XXI. Decoupling

A. Introduction

In its initial filing in this proceeding, the Company proposed a Revenue Decoupling Rider tariff.[33] Decoupling is a regulatory tool designed to separate a utility's revenue from changes in energy sales.[34]

Under traditional rate regulation, natural gas utility revenues are affected by the utility's ability to control costs and by sales made to accommodate customers' energy consumption. Ordinarily, then, utility revenues increase as sales increase. Traditionally regulated utilities therefore have an

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[33] Initial Filing – Volume 1 – General Rate Petition, Proposed Tariffs, Proposed Original Page 28 – 28.a (August 2, 2013).

[34] Minn. Stat. § 216B.2412, subd. 1.

incentive to promote (or not diminish) incremental sales of natural gas. Put another way, this "throughput incentive" discourages utilities from promoting energy conservation.

A properly implemented decoupling mechanism aligns the utility's interests with the public's interest in energy efficiency by limiting or severing the connection between unit sales of natural gas and revenue. Practically, decoupling is accomplished by periodically adjusting the utility's rates in response to deviations in sales from sales forecasts. This increases the significance of sales forecast accuracy for ratepayers, which is addressed elsewhere in this order.

Decoupling sales and revenues may be achieved through "full" or "partial" decoupling mechanisms. With full decoupling, departures from sales forecasts for any reason are accounted for and subject to true-up. Partial decoupling functions similarly, but excludes some sales and forecasts divergences from true-up, such as those attributable to weather. The Company proposed and supports a full revenue decoupling mechanism.

Minnesota Statutes § 216B.2412 authorizes the Commission to approve pilot decoupling programs. As required by the statute, the Commission established standards and criteria for decoupling pilot proposals in June 2009.[35] The Commission has previously approved decoupling pilot programs for the Company in 2010 (partial decoupling),[36] and for Minnesota Energy Resources Corporation in 2012 (full decoupling).[37] The Company's partial decoupling pilot expired on June 30, 2013.

B. Positions of the Parties

1. The Company

According to the Company, the purpose of the proposed Revenue Decoupling Rider was to reduce the Company's financial disincentive to promote energy efficiency and conservation "by severing the link between the recovery of [the Company's] non-gas distribution costs and the volume of gas delivered to its small volume firm customer rate classes." As initially proposed, the Revenue Decoupling Rider would have applied to customers in the Company's residential, small volume commercial and industrial, and small volume firm transportation customer classes.

In response to Department concerns raised during the contested case proceeding, the Company agreed to certain modifications of its initial Revenue Decoupling Proposal. These modifications were:

i. a 10% cap on non-gas margin revenue, after removing conservation costs, for a decoupling adjustment on occasions of under-recovery during an evaluation period;

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35 *In re: a Commission Investigation into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling, Docket No. E,G-999/CI-08-132 (June 30, 2008).

36 *In re: an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Findings of Fact, Conclusions of Law, and Order, Docket No. G-008/GR-08-1075 (January 11, 2010).

37 *In re: the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Findings of Fact, Conclusions, and Order, Docket No. G-007,011/GR-10.977 (July 13, 2012).

ii. broadening the decoupling proposal to apply to all customer classes except market-rate customers; and

iii. an agreement concerning a proposed evaluation plan for the proposed Revenue Decoupling Rider.

But in its brief to the ALJ after the record closed, the Company withdrew its support for decoupling in this case. The Company stated that it viewed the possibility of partial decoupling—which the Department was advocating—as a negative result for the Company and its customers in light of its experience with the Company's recently expired partial-decoupling pilot. Absent widespread support for its full decoupling proposal, and because it would prefer no decoupling mechanism to a partial decoupling mechanism, the Company asserted that it no longer sought approval of any decoupling mechanism.

In its oral argument to the Commission, however, the Company stated that it still supports full decoupling, and stands by its decoupling-related testimony.

2. The Department

The Department initially supported the premise that both full and partial decoupling serve the goal of reducing the Company's disincentive to promote energy savings.[38] In the course of the contested case, the Department recommended revisions to the Company's proposed full Revenue Decoupling Rider, and continued to support reinstatement of the Company's expired partial decoupling pilot as an alternative to the Company's proposal.

In its Exceptions, the Department stated that the options to order no decoupling, partial decoupling, or full decoupling were properly before the Commission. But the Department construed the Company's position late in the contested case proceeding—supporting either full decoupling or no decoupling—to imply that the Company lacked a sufficient conservation disincentive to warrant decoupling. The Department ultimately recommended that the Commission direct interested parties to further investigate the effects on ratepayers of full, partial, and no decoupling.

According to the Department, if a decoupling mechanism is approved in this case, the Commission should approve partial decoupling "if the primary purpose of the decoupling mechanism is to remove [the Company's] disincentive to investing in energy conservation," and should approve full decoupling only if the Commission seeks to serve the energy conservation goal and a revenue stabilization goal.

3. The Office of the Attorney General

The OAG opposed the Company's full decoupling proposal, and accepted the Company's withdrawal of its proposal. At oral argument, the OAG opposed Commission action on decoupling proposals in this proceeding in light of the Company's withdrawal. But during the contested case proceeding the OAG opposed the proposal.

The OAG expressed concern about decoupling's effect on customers' understanding of their bills and about customer perception of the relationship between decoupling and energy conservation.

[38] Limited Exceptions of the Minnesota Department of Commerce to the ALJ Report, 7 (April 21, 2014).

Because decoupling adjustments are not made close in time to the events that cause them, the OAG believes that the decoupling proposal would send mixed price signals to customers. And, because decoupling surcharges can arise from sales decreases regardless of the reason, the OAG expressed concern that customers' mindset toward conservation could be soured.

The OAG made several recommendations for modifications to the Company's proposal if the Commission were to approve decoupling in this case. Among them, the OAG recommended that the Commission authorize the proposal as a pilot program, and that the proposal extend to all customer classes.[39]

4. The Environmental Intervenors

The Environmental Intervenors support the Company's proposal to implement full decoupling, with modifications recommended by the Department and agreed to by the Company. The Environmental Intervenors assert that the record supports a determination that a full decoupling proposal is reasonable and would serve the purposes of Minn. Stat. § 216B.2412.

C. The Recommendation of the Administrative Law Judge

The ALJ's decoupling-related findings and conclusions appear in paragraphs 720 – 769 of the report. The ALJ concluded that the record lacked evidence to support implementing a partial decoupling mechanism, and recommended that the Commission either exclude a decoupling mechanism from its final order (because the Company had withdrawn its request) or implement a full decoupling mechanism, either outright or as a pilot program.

Although the Company withdrew its support for decoupling after the close of the evidentiary record, the ALJ made 15 specific findings in support of her alternative recommendations to nevertheless order decoupling in this case. Among the findings, the ALJ found that that the full decoupling proposal "would reduce the Company's disincentive to promote energy efficiency," and that partial decoupling "has produced at least one example of an irrational result . . . and could easily do so again in the future if partial decoupling is re-implemented."

D. Commission Action

The Commission adopts the ALJ's analysis, findings, and conclusions found in paragraphs 720 – 769, with the modifications detailed below. Specifically, the Commission will order that the Company implement as a pilot program its full decoupling proposal, modified in a manner consistent with its surrebuttal testimony.

There is no dispute among the parties, and the Commission so finds, that the record in this proceeding presents the Commission a range of options with regard to revenue decoupling. Before the Company withdrew its decoupling proposal, the parties presented testimony concerning full and partial decoupling alternatives. The result is a robust record, adequate to support a Commission determination on this issue. The Commission agrees with the ALJ and the parties that approving a decoupling mechanism would be a valid exercise of the Commission's authority.

[39] Direct Testimony of Vincent C. Chavez, 57 – 58 (November 26, 2013).

The Commission concludes that on this record, directing the modified full-decoupling proposal to be implemented as a pilot program best serves the Commission's statutory mandates. These mandates include establishing just and reasonable rates that to the maximum reasonable extent encourage energy conservation,[40] and assessing the merits of rate decoupling to promote energy efficiency and conservation.[41]

The modified decoupling proposal incorporates changes to accommodate certain Department and OAG criticisms of the Company's initial proposal. The ALJ found that:

> 737. The Department initially had four areas of disagreement with the Company related to its proposed RD Rider. Three of the issues were resolved between the Company and the Department. The resolved issues are:
>
> a. The Company agreed to a ten percent cap on non-gas margin, after removing conservation costs, for a decoupling adjustment in the case of an evaluation period where an underpayment was determined. This was a change from the original proposal of five percent on the total volumetric charge, and is consistent with the proposal approved by the Commission in the MERC decoupling pilot program.
>
> b. The Company agreed to broaden its initial proposal for full decoupling to include [. . .] all other classes, except its market rate classes.
>
> c. The Company and the Department came to an agreement regarding a proposal evaluation plan for the proposed full RD Rider.[42]

The only remaining dispute between the Company and the Department was whether the Department would support full decoupling or would only recommend partial decoupling.[43]

The Department stated its final position on decoupling in the alternative: it recommended further investigation of decoupling's impact on ratepayers or, if the Commission were to approve a decoupling mechanism in this case, the choice between full or partial decoupling should be guided by the Commission's goals for the decoupling program. According to the Department, the Commission should impose full decoupling *only* if the Commission has a revenue stabilization goal for the Company. The Commission agrees with the Department's goal-oriented approach, but reaches a different conclusion.

The Commission agrees with the Department that selecting a decoupling mechanism should be guided by the Commission's statutory and policy goals concerning such programs. In this instance,

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[40] Minn. Stat. § 216B.03.

[41] Minn. Stat. § 216B.2412.

[42] (Footnotes omitted.)

[43] ALJ's Report, ¶ 738; *see also* Limited Exceptions of the Minnesota Department of Commerce to the ALJ Report, 8.

these goals include the statutory goal for pilot decoupling programs: to assess the merits of a rate decoupling strategy to promote energy efficiency and conservation.[44] This goal can be served best through a decoupling program that offers new information about decoupling's effectiveness.

The Commission has previously approved two decoupling pilot programs. One partial decoupling program was implemented by the Company from 2010 to 2013. The other, a full decoupling program implemented by Minnesota Energy Resources Corporation is just now underway. The Commission concludes that the modified full decoupling proposal in this proceeding is an appropriate addition to the list of pilot programs intended to aid the Commission in assessing rate decoupling's merits as a regulatory tool.

The modified full decoupling proposal serves the relevant statutory goals by differing from both previously approved decoupling programs. This program applies to more customer classes than the MERC decoupling pilot, and it will involve a more extensive customer education effort than has previously been attempted in Minnesota. The three-year pilot term, the maximum allowed by statute, will allow the Commission to evaluate decoupling's impact over three different heating seasons. Implementing full decoupling as a pilot project, therefore, allows additional assessment of the effects of decoupling, which is recommended by the Department and authorized by the revenue decoupling statute.

In light of concerns about the possible effects on customers, including confusion about their bills and uncertainty about the relationship between decoupling and energy conservation efforts, the Commission will delay the implementation until July 1, 2015. Delayed implementation will allow the Department, the Company, and other interested stakeholders to develop and implement a plan to help customers better understand the goals and functions of decoupling. This education and outreach program will mitigate potential customer confusion related to decoupling's effects on customer bills and its relationship to customer energy conservation.

The decoupling pilot adequately avoids adverse ratepayer impact through the parties' careful attention in this case to the Company's sales forecast, and by including a 10% cap on underpayment-related decoupling surcharges. Together, these factors serve to constrain annual swings in rates that might otherwise arise due to weather volatility. As discussed in the Commission's order establishing standards for pilot decoupling programs, the Commission may take appropriate action if it determines that the pilot is harming ratepayers or failing to meet objectives.

Finally, the Commission disagrees with the Department's contention that the Company's disfavor for partial decoupling, or its change in positions as this case developed, implies that the Company lacks a throughput incentive. The Department's inference is unsupported by a preponderance of the record evidence. Conversely, the ALJ found that full decoupling "would reduce the Company's disincentive to promote energy efficiency." The Commission agrees with this finding. The Company established that, more likely than not, it has a throughput incentive, and decoupling will fully separate the Company's revenue from changes in energy sales. The Commission concludes that full decoupling has substantial potential to align the Company's interests with the public's interest in energy efficiency.

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[44] Minn. Stat. § 216B.2412, subd. 3.

The decision to implement full decoupling as a pilot program is consistent with the ALJ's detailed findings and considered recommendations on this issue. It is also consistent with the goals and statutory mandate of the Commission. The Commission will direct that the pilot program be in effect for three years and start on July 1, 2015. Before the program goes into effect, the Commission will require the Company to work with interested stakeholders to develop proposals concerning evaluation reports and an education and outreach program concerning the goals and operation of revenue decoupling.

XXII. Customer Charges for Residential and Small Commercial and Industrial Customers

A. Introduction

The monthly customer charge is a fixed monthly charge assessed without regard to usage levels. It is designed to help recover fixed customer-related costs such as the cost of meters, service lines, meter reading, and billing.

The Company's current monthly residential customer charge is $8 per month. According to the Company's Class Cost of Service Study, the fixed monthly cost of serving a Residential class customer is $21.96. For the Small Volume Commercial and Industrial customer classes, the Company's current monthly charge and fixed monthly cost-to-serve are as follows:

	Current Customer Charge (per month)	**Monthly Fixed Cost to Serve**[45]
C&I – A	$12.00	$22.71
C&I – B	$18.00	$26.51

B. Positions of the Parties

1. The Company

CenterPoint proposed to increase the monthly customer charges for residential customers to $15.00 to move the charge closer to the CCOSS average cost of service. The Company argued that its current residential customer charge of $8 collects 29% of the class's fixed costs, while its proposed increase would result in customer charges collecting 61% of those costs. It identified three possible advantages for customers arising from an increased customer charge: (1) moderated bill volatility month-to-month and reducing bills in high-usage months; (2) reduced effect of weather volatility on customers and the Company; and (3) improved intra-class rate design equity.

The Company asserted that its proposals represent a large but justified movement towards cost, and argued that the proposed increase would not result in rate shock because the impact on affected customers' total bills would be negligible or nonexistent. The Company also argued that the proposed increase in customer charges poses little risk of interfering with conservation incentives because a large proportion of residential customer bills will still be determined by usage.

The Company also proposed increasing the Small Volume Commercial and Industrial Class customer charges. It proposed to increase the C&I – A class to $15, and the C&I – B class to $21.

[45] According to the Company's accepted Class Cost of Service Study 2.

2. The Department

The Department agreed in principle with many of CenterPoint's rate-design-related arguments in support of increasing the residential customer charge, but argued that the Company's recommended increase could result in rate shock and was therefore unreasonable. The Department recommended that the Residential customer charge be increased to $9.50, asserting that a $1.50 increase would be reasonable and consistent with the customer charges the Commission has approved for Minnesota utilities in recent rate cases. The Department further argued that its recommendation is not dependent on whether or not the Commission approved decoupling.

The Department did not object to the Company's proposed Commercial and Industrial customer charge increases.

3. The OAG

The OAG opposed the Company's proposed increase in the customer charge in each of these classes, and recommended that the Commission approve no increase. The OAG argued that the Company's request was a large and sudden increase that would result in rate shock. The OAG also asserted that public comments taken during the course of record development did not support an increased residential customer charge.

4. The Environmental Intervenors

The Environmental Intervenors argued that an increase of the size the Company proposed would negatively affect conservation and would penalize low-usage customers while benefiting high-usage customers. They also argued that increases in the customer charge discourage energy conservation.

They reasoned that among the justifications for an increased customer charge was the goal of improving the Company's ability to recover fixed costs even in the face of variable usage—and that decoupling serves the same goal. Accordingly, the Environmental Intervenors argued that if the Commission approved a decoupling mechanism, it should deny the Company's requested residential customer charge increase.

5. The Suburban Rate Authority

The Suburban Rate Authority argued that the Company did not adequately support its proposal to increase the residential customer charge to $15.00. It further argued that the ALJ's proposed $12.00 increase was also larger than warranted by the record.

According to the SRA, the Company should be required to address issues of rate shock and conservation disincentives persuasively before a substantial increase in the customer charge should be approved. The SRA took issue with the design of a customer survey that CenterPoint used to support its proposal. It pointed out that the Commission's past practice has been to impose increases of the customer charge between 12 and 20 percent. The SRA argued that in light of the entire record and past Commission decisions on customer charge increases, the Company had adequately supported an increase to $9.00.

C. The Recommendation of the Administrative Law Judge

The ALJ's customer-charge-related findings and conclusions appear in paragraphs 640 – 719 of the report. The ALJ recommended that the Commission increase the monthly residential customer charge to $12.00 per month, with an appropriate, corresponding downward adjustment to the class's per-therm charge.

In recommending a $12.00 monthly customer charge, the ALJ found that "a reasonable increase in the monthly charge is compatible with full decoupling,"[46] and that "[s]hould the Commission choose not to implement the Company's original full decoupling proposal, an increased monthly charge will be the only protection that the Company and the customer have against erratic weather" causing volatility in revenue and monthly bills.[47]

The ALJ concluded that the Company demonstrated the reasonableness of its proposed $3 increases in the Commercial and Industrial A & B classes. The ALJ recommended those increases be approved.

D. Commission Action

Having reviewed the record, including the oral and written arguments of all parties and members of the public, the Commission concludes that a $9.50 monthly residential customer charge, with an appropriately reduced per-therm charge, is appropriate. Accordingly, the Commission will reject ALJ finding #706, concerning the ALJ's recommended $12.00 customer charge. But the Commission agrees that the proposed Commercial and Industrial customer charges are warranted, and will adopt the ALJ's recommendation for those classes.

The Commission's decision on revenue decoupling in this proceeding informs its determination on this issue. As argued by the Environmental Intervenors, and alluded to by the ALJ, full revenue decoupling achieves a revenue-stabilization objective that might otherwise be accomplished by an increased customer charge. Both effectively reduce revenue volatility for the Company, protecting its ability to recover fixed costs from unexpected usage variations caused by weather or other factors.

The Commission's decision to approve full revenue decoupling has therefore addressed a primary justification offered for the residential customer charge increase recommended by the Company and by the ALJ. Among the reasons offered by the ALJ to support her recommended $12.00 charge was the Company's contention that a $12.00 charge was necessary "to protect itself and its customers from the worst effects of erratic weather" in the absence of decoupling.[48] Given the protection provided by revenue decoupling, the Commission will not approve the Company's proposed increase and, while the ALJ's recommendation is more moderate than that proposed by the Company, the Commission will not adopt the increase recommended by the ALJ.

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[46] ALJs Report ¶ 692.

[47] ALJ's Report ¶ 692.

[48] ALJ's Report ¶¶ 661 and 704, citing Rebuttal Testimony of Burl M. Drews at 13– 14. Mr. Drews testified that "[i]n the current case, an increase in the basic charge to $12 is required just to maintain this same $9 million of risk to both customers and the Company of abnormal weather [as the $8 customer charge then in effect]."

The Commission concludes, however, that a modest increase in the residential customer charge remains appropriate. Maintaining the customer charge at its current level would effectively increase intra-class subsidies for low-usage customers, so the principle of intra-class rate design equity supports some increase.

Having determined that the ALJ's recommended increase is larger than warranted, the Commission concludes that the Department-recommended residential customer charge amount of $9.50 best balances the many remaining concerns identified by all the parties. These concerns include, but are not limited to: the principle of moving the fixed cost charge closer to the class's average fixed cost; promoting intra-class equity; minimizing rate shock that certain customers may experience in response to a large, sudden change in the fixed monthly charge; and the Commission's mandate to set rates that to the maximum reasonable extent encourage energy conservation.

A $1.50 increase in the monthly residential customer charge—with a corresponding decrease in the per-therm charge—is a reasonable step toward recovery of the residential class's fixed costs in the fixed charge while appropriately minimizing conservation disincentive and possible rate shock effects. For these reasons, the Commission also concludes that the proposed $3 increases in the Commercial and Industrial classes are appropriate.

XXIII. Customer Charges for Small Volume Dual Fuel, Large Volume Dual Fuel, and Large Volume Sales and Transportation Customers

A. Introduction

The Company recommended no change in the customer charges for customer classes other than the residential and Commercial and Industrial A and B classes.

The Department disagreed, recommending keeping the customer charge for Commercial and Industrial Class C at current levels but making modest reductions to the customer charges for the Small Volume Dual Fuel A and B classes and increasing the customer charges for large volume sales and transportation customers.

B. Positions of the Parties

The Company opposed reducing Small Volume Dual Fuel customer charges on grounds that those charges are currently below cost and opposed increasing customer charges for large volume sales and large volume transportation customers on grounds that, since their revenue responsibilities would essentially remain constant under final rates, there was no need for a change in their intra-class rate design. The Company also emphasized the need to maintain neutrality between sales and transportation service by keeping the differential between sales and transportation service at $100 per month.

The Department challenged the claim that Small Volume Dual Fuel customer charges were below cost, stating that they were higher than the customer costs identified in the class cost of service study, on which the Company based other customer charges, and were only below cost when capacity costs were added. The Department argued that there was no reasonable basis to single out the Small Volume Dual Fuel customers in this way.

The Department also argued that there was no reasonable basis to exclude the remaining customer classes from the general principle that—all things being equal—customer charges should be set to recover customer costs.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with the Department.

She found that the Company had not adequately explained why the customer charge for the Small Volume Dual Fuel class should include capacity charges, when those charges were excluded from the customer charges of other classes. She found that the Company had not provided a reasoned justification for excluding large volume customer classes from its stated goal of aligning customer charges with customer costs. She found that the Company had provided no reasonable basis for treating these customer classes differently from other customer classes.

She found that the Department's recommended customer charges maintained neutrality between sales and transportation service by maintaining the existing $100 customer-charge differential, adequately addressing that policy concern raised by the Company.

She concluded that the Company had failed to establish the reasonableness of its proposed customer charges for these classes and recommended adopting the customer charges recommended by the Department.

D. Commission Action

The Commission concurs with the Administrative Law Judge on these issues and accepts her findings, conclusions, and recommendations. The Commission will adopt the Department's recommended customer charges for these customer classes, as set forth below:

- SVDF – A — Decrease from $60 to $50
- SVDF – B — Decrease from $90 to $80
- LVDF – Sales — Increase from $600 to $700
- LVDF – Transportation — Increase from $700 to $900
- LVF – Transportation — Increase from $700 to $900

FINANCIAL SCHEDULES AND COMPLIANCE

XXIV. Overall Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a Minnesota jurisdictional total gross revenue deficiency of $32,943,000, as shown below:

Revenue Requirement Summary
Test Year Ending September 30, 2014
($000s)

Average Net Rate Base	$700,248
Rate of Return	7.42%
Required Operating Income	$51,958
Operating Income	$32,643
Operating Income Deficiency	$19,315
Gross Revenue Conversion	1.7056
Revenue Deficiency	$32,943

B. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is $700,248,000, as shown below:

Rate Base Summary
Test Year Ending September 30, 2014
($000s)

Utility Plant in Service:	
Intangible	$1,589
Production	$18,989
Underground Storage	$20,981
Other Storage	$16,507
Distribution	$1,379,849
General	$148,115
Total Utility Plant in Service	$1,586,030
Accumulated Reserve:	
Intangible	$940
Production	$17,303
Underground Storage	$19,770
Other Storage	$17,471
Distribution	$654,488
General	$90,894
Total Accumulated Reserve	$800,866

Net Utility Plant in Service:	
Intangible	$649
Production	$1,686
Underground Storage	$1,211
Other Storage	($964)
Distribution	$725,361
General	$57,221
Total Net Utility Plant in Service	$785,164
Construction Work in Progress	$0
Net Acquisition Adjustment	$0
Gas Stored Underground-Noncurrent	$177
Customer Advances for Construction	($241)
Accumulated Deferred Income Taxes	($132,792)
Working Capital:	
Materials and Supplies	$9,474
Gas Stored Underground-Current	$34,288
Liquefied Natural Gas Stored	$1,473
Liquefied Petroleum (Propane) Gas	$4,207
Prepayments	$1,246
Other Deferred Debits & Credits	($14,588)
Other Cash Working Capital	$11,841
Total Working Capital	$47,941
Average Net Rate Base	$700,248

C. Operating Income Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the test year under present rates is $32,643,000, as shown below:

Statement of Operating Income
Test Year Ending September 30, 2014
($000s)

Operating Revenue	
Sales of Gas	
Residential	$503,195
Commercial & Industrial	$201,047
Total Firm	$704,242
Dual Fuel	$122,536
Transportation	$18,614
Other	$1,389
Less: Franchise Fees	$0
Total	$846,781
Late Payment Charges	$2,746
Other Operating Revenue	$0
Total Operating Revenue	$849,527
Operating Expenses	
Operation and Maintenance	
Cost of Gas Purchases	$560,412
Production	$866
Other Gas Supply	$802
Underground Storage	$870
Other Storage	$634
Distribution	$31,245
Customer Accounts	$32,786
Customer Service & Informational	$31,495
Sales	$505
Administrative & General	$34,590
Total Operation	$694,205
Maintenance Expenses	$19,916
Total Operation & Maintenance	$714,121
Depreciation and Amortization	$61,813
Federal & State Income Taxes	$6,575
Deferred Income Taxes	$4,521
Investment Tax Credit Adjustment	($463)
Other Taxes	$30,317
Total Operating Expenses	$816,884
Operating Income Before AFUDC	$32,643
Allowance for Funds Used During Construction	$0
Utility Operating Income	$32,643

XXV. Compliance Filing Required

The Commission will require the Company to make a compliance filing within 30 days of the date of this order showing the final rate effects of the decisions made here and proposing a plan for refunding the difference between the amounts it collected in interim rates and the amounts it is authorized to collect in final rates. The Commission will establish a brief comment period to give interested persons a chance to review and comment on that filing.

ORDER

1. CenterPoint Energy Minnesota Gas is entitled to increase Minnesota jurisdictional revenues by $32,943,000 to produce jurisdictional total gross revenue of $882,470,000 for the test year ending September 30, 2014.

2. The Commission accepts, adopts, and incorporates the findings, conclusions, and recommendations of the Administrative Law Judge, except as set forth herein.

3. Beginning on July 1, 2015, the Company shall implement a full Revenue Decoupling Rider, with modifications consistent with the Company's Surrebuttal Testimony, as a three-year pilot project. The Company shall work with the parties and interested stakeholders to develop and file, within 60 days of the date of this order, a compliance filing that includes proposals for:

   A. annual evaluation reports that provide the same (or similar) information as required in the Company's first revenue decoupling pilot program (Docket No. G-008/GR-08-1075), and
   B. developing a comprehensive, effective, and meaningful education and consumer outreach program that sets forth the goals of, and explains, revenue decoupling.

   Persons wishing to comment on the compliance filing shall do so within 30 days of the date it is filed.

4. The Company's Conservation Improvement Plan test-year expense and per unit-of-energy cost allocation are hereby approved. The Company shall update the Conservation Cost Recovery Charge (CCRC) factor to reflect the updated sales forecast.

5. The interest synchronization methodology proposed by the Department of Commerce is hereby accepted; the final interest-synchronization adjustment shall be based on final Commission-approved figures.

6. The Company shall make a balance sheet adjustment to reflect that the fleet fuel price has been set at the EIA's September 30, 2013, 12-month average of $3.46 per gallon and shall include that adjustment in its post-order compliance filing calculations.

7. The Company shall adjust its rate base to properly reflect the level of capitalized pension costs approved for rate recovery herein.

8. The Company shall adjust its rate base to properly remove the capitalized non-qualified pension costs commensurate with the disallowed non-qualified pension expense.

9. The Company shall adjust its rate base to properly remove the capitalized non-qualified savings plan costs commensurate with the disallowed non-qualified savings plan expense.

10. The Commission denies rate recovery of CenterPoint Energy's Long-Term Incentive Plan expense as recommended by the Administrative Law Judge, but corrects the amount of the disallowed test-year expense to $258,094, as explained above.

11. The Company shall track rate recovery of the rate case expenses authorized for recovery in this case for refund of any over-recovery in the next rate case. That refund shall include interest at the overall rate of return approved in this case.

12. The Company shall refund to ratepayers the difference between CenterPoint's *approved* rate-case expenses in its last rate case ($1,490,736) and the actual amount recovered during the 57-month period ($2,360,332), an $869,596 difference. That refund shall include interest at the 8.09% overall rate of return approved for the Company in its last rate case and shall be made at the same time as the interim rates refund.

13. The Company shall refund to customers all incentive compensation amounts approved by the Commission and included in base rates, but not paid to employees. The Company shall file an annual report within 30 days from the date incentive compensation is normally scheduled for payout, setting forth the following information:

    A. a description of the incentive compensation plan;
    B. the accounting of amounts of unpaid incentive compensation built into rates to be returned to ratepayers;
    C. an evaluation of the incentive compensation plan's success in meeting its stated goals, including the payout ratio; and
    D. a proposal for refund, if applicable.

14. The Commission modifies findings 331, 332, and 333 of the Administrative Law Judge's Report, as set forth below:

> 331. The Department again acknowledged that the Company's LNG revenues are largely contract-based and agreed that the Company had testified that the largest contract from the fall of 2013 was a one-time sale that is not expected to reoccur. ~~The Department did not produce any evidence to respond to these facts.~~
>
> 332. The Department maintained that the Company's initial adjustment to its test-year LNG Margin was incomplete and one-sided, in a fashion that was adverse to ratepayers. The Department recommended that the assumed test year revenues be set at actual 2013 revenues in light of the contracts signed in October 2013 that were not considered by the Company ~~despite the lack of contracts shown in the record~~.

> 333. The Administrative Law Judge agrees that the nature of the LNG revenue stream makes it difficult to predict future income, without proof of contracts in place or a showing by the Company that they are or are not likely to arise. A test-year number must have some reasonable basis; the burden to make this showing is on the Company. ~~It is not reasonable to count as predicted test-year income, revenue from a contract which is not guaranteed to be signed, and as to which the Company testified it has no information regarding the customer's future intent to purchase LNG.~~ The Company testified at the hearing that it has only one LNG contract for 2014. ~~The Department produced no evidence to rebut that testimony. Therefore, the Administrative Law Judge concludes that the Department's recommendation is not reasonable.~~

15. The Commission revises the Administrative Law Judge's findings 370 and 371, as set forth below, for purposes of clarifying the underlying reasoning; the Commission does not adopt the recommendation to set the discount rate at 7.25%, as discussed above:

> 370. However, the Administrative Law Judge does not agree with the Department that a reasonable expected long-term growth rate is 8.0 percent. Although 8.0 percent is consistent with the Company's historical long-term expected return on plan asset rate of 8.0, the Company demonstrated that it is not now, nor is it likely in the future, to be earning an 8.0 percent return on its pension fund. The Company made a prudent decision, consistent with federal policy and law, to reduce the risk to its pension funds. This decision may well save the Company, its employees, and perhaps even its ratepayers, costs in the future. In a future rate case, the Company will bear the burden of making such a showing based on facts at that time. ~~The Department provided no precedent for its argument that the Commission should have approved the Company's shift in investment approaches, especially given that~~ For purposes of this rate case, the Company's decision to move away from equity and toward fixed-income funds to protect the pension funds and work toward fully funding them appears to be reasonable ~~was consistent with federal policy~~.
>
> 371. The Company demonstrated that the shift in pension fund assets reduced returns on that fund immediately. The Company expressed no intention to return to its previous distribution of assets that would result in a higher return. ~~Therefore, t~~The Company's request for an expected long-term growth rate of 7.25 percent for its pension plan fund is reasonable and supported by the evidence. The Administrative Law Judge recommends that the Commission establish test-year pension expense for both the discount rate and the long-term growth rate at 7.25 percent.

16. In its next rate case, the Company shall discuss its approach to inter-jurisdictional cost allocation and the underlying jurisdictional cost allocation factors, as applied to the base year amount and as applied to test year adjustments, in the development of its test year revenue requirement.

17. In its next rate case, the Company shall identify and explain any changes it has made to its jurisdictional cost allocation factors and any changes in how those factors are used during the course of the next rate case proceeding.

18. In its next rate case, the Company shall present in the public summary schedules the allocation of revenue responsibility for each customer class that is listed in its tariff and not combine customer classes together when presenting its summary of the proposed revenue allocation.

19. In its next rate case, the Company shall provide additional information on curtailments and its curtailment forecasting methodology, as recommended by the Department and agreed to by the Company.

20. In its next rate case, the Company shall substantiate its forecasting methodology in regard to curtailments and weather-normalized sales, as recommended by the Department and agreed to by the Company.

21. In its next rate case, the Company shall, in consultation with the Department, provide a comprehensive examination of the predictive power, volatility, and impact on test year and future revenues of using 10-year, 15-year, and 20-year weather data in the forecast.

22. In its next rate case, the Company shall file a minimum system study based on a one-inch and a zero-inch pipe, in addition to a two-inch pipe.

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

24. In the initial filing of its next rate case, the Company shall provide descriptive information relating to travel, entertainment, and related employee expenses under Minn. Stat. § 216B.16, subd. 17. To ensure that future schedules contain the required information, the Company shall develop a proposal to resolve current insufficiencies and present the proposal to the OAG and the Department in advance of its next rate case filing.

25. In the initial filing in its next rate case, the Company shall address in detail the reasonableness of allocating capacity-related costs to ICCC customers along with a discussion of each capacity-related cost that is avoided due to the ICCC customers taking interruptible service and each capacity related-cost that would be incurred if an ICCC customer switched to firm service.

26. In future rate cases, if the Company proposes an interim rate refund adjustment as a result of a Reconnection Fee increase, the Company shall calculate and disclose its proposed adjustment amount at the time it proposes the adjustment.

27. In its initial filing in future rate cases, the Company shall discuss and explain sales and margin changes for each of its liquefied natural gas contracts.

28. In future rate case filings the Company shall separately report the amount of capitalized jurisdictional pension cost, rather than combining that cost with non-regulated pension cost.

29. Within 30 days of the date of this order, the Company shall make a compliance including the following items:

    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:

        1. Breakdown of Total Operating Revenues by type;
        2. Schedules showing all billing determinants for the retail sales (and sale for resale) of natural gas. These schedules shall include but not be limited to:
            a) Total revenue by customer class;
            b) Total number of customers, the customer charge and total customer charge revenue by customer class; and
            c) For each customer class, the total number of commodity and demand related billing units, the per unit of commodity and demand cost of gas, the non-gas margin, and the total commodity and demand related sales revenues.

    B. Revised tariff sheets incorporating authorized rate design decisions.

    C. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

    D. A revised base cost of gas, supporting schedules, and revised fuel adjustment tariffs to be in effect on the date final rates are implemented.

    E. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

    F. 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.

    G. Because final authorized rates are lower than interim rates, a proposal to make refunds of interim rates, including interest to affected customers.

    Persons wishing to comment on the compliance filing(s) shall do so within 30 days of the date it is filed. Comments are not invited on the proposed customer notice.

30. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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