BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

ISSUE DATE: July 13, 2012

DOCKET NO. G-007, 011/GR-10-977

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

PROCEDURAL HISTORY

I. Initial Filings

On November 30, 2010, Minnesota Energy Resources Corporation (MERC) filed this general rate case seeking an annual increase of some $15,165,309, or approximately 5.18% over current rates, in the retail rates of its two operating divisions, MERC-PNG and MERC-NMU.[1] As part of its filing, MERC requested rate area consolidation of its two operating divisions. The filing included a proposed interim rate schedule.

On January 28, 2011, the Commission issued three orders in this case: one finding the rate case filing substantially complete and suspending the proposed final rates; one referring the case to the Office of Administrative Hearings for contested case proceedings; and one setting interim rates for the period during which the rate case was being resolved.

Also on January 28, the Commission issued an order setting a new base cost of gas for the period during which interim rates would be in effect.[2]

II. The Parties and Their Representatives

The following parties appeared in this case:

[1] The request for MERC-PNG was $13,718,788, or approximately 5.89%, and for MERC-NMU was $1,446,517, or approximately 2.4%.

[2] *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a New Base Cost of Gas for Interim Rates in Docket No. G-007,011/GR-10-978*, Order Setting New Base Cost of Gas, Docket No. G-007,011/MR-10-978 (January 28, 2011).

- Minnesota Energy Resources Corporation (MERC or the Company), represented by Michael J. Ahern, Karly Baraga Werner, and Amber S. Lee, Dorsey & Whitney LLP.

- Minnesota Department of Commerce, Division of Energy Resources (the Department), represented by Karen Finstad Hammel, Assistant Attorney General.

- The Antitrust and Utilities Division of the Office of the Attorney General (the OAG), represented by Ronald M. Giteck, Assistant Attorney General.

- Hibbing Taconite Company; ArcelorMittal USA, Minorca Mine; Northshore Mining Company; United Taconite, LLC; United States Steel Corporation, Minntac and Keewatin Mines; and USG Interiors, Inc., (the Super Large Gas Intervenors or SLGI), represented by Andrew P. Moratzka, Mackall, Crounse & Moore, PLC.

- Minnesota Center for Environmental Advocacy and the Izaak Walton League of America – Midwest Office, represented by Elizabeth Goodpaster, Attorney at Law.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Manuel J. Cervantes to hear the case.

The parties filed direct, rebuttal, surrebuttal, and sur-surrebuttal testimony prior to the opening of evidentiary hearings and initial and reply briefs after the close of evidentiary hearings. The ALJ held evidentiary hearings in St. Paul on October 24-26, 2011.

The ALJ also held public hearings in the case, in Rochester and Rosemount on June 23, 2011, and in Cloquet on June 27, 2011. No members of the public attended the first two hearings; seven members of the public attended the hearing in Cloquet. Some 27 members of the public submitted written comments.

The public comments generally opposed any significant rate increase, emphasizing the disruption and hardship that might result from rate increases during the current economic downturn, especially for those who were unemployed or on fixed incomes. Several people pointed out that natural gas prices were at or near record lows and urged the Company to treat this as an opportunity to hold the line on prices. Several people also argued that the Company should more aggressively seek opportunities to cut costs.

IV. Proceedings Before the Commission

On April 2, 2012, the Administrative Law Judge filed his Findings of Fact, Conclusions and Recommendation (the ALJ's Report).

On April 17, 2012, the Company, the Department, and the OAG filed exceptions to the report of the Administrative Law Judge under Minn. Stat. § 14.61 and Minn. Rules, part 7829.2700.

On May 22 and May 24, 2012, the Commission heard oral argument from and asked questions of the parties. On May 24, 2012 the record closed under Minn. Stat. § 14.61, subd. 2.

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

FINDINGS AND CONCLUSIONS

I. Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[3] 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.[4] 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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[3] Minn. Stat. § 216B.16, subds. 4, 5, and 6.

[4] *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.[5]

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.[6] Any doubt as to reasonableness is to be resolved in favor of the consumer.[7]

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

[5] *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).

[6] Minn. Stat. § 216B.16, subd. 4.

[7] Minn. Stat. § 216B.03.

> proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[8] (Citation omitted.)

II. Summary of Issues

The parties worked effectively to narrow the issues in this case, and by the date of oral argument, only the issues listed below remained contested:

Decoupling Pilot Program and Related Issues

- *Pilot Program Structure and Content* - Does the proposed decoupling pilot program merit Commission approval under Minn. Stat. § 216B.2412 and the Commission order issued to implement that statute?

- *Timing of Decoupling Proposal Implementation* – When should the decoupling program take effect?

Cost of Capital

- *Return on Equity* – What rate of return on common equity is currently appropriate for MERC?

Financial Issues

- *Sales Forecast* – Should the Company's initial or revised sales forecast be used to set rates in this proceeding?

- *Billing System Audit* – Is Commission action required to ensure the adequacy of the audit of MERC's billing system?

- *Pension Costs* – Has the Company properly calculated its test-year pension expense, given the historical volatility of pension costs?

- *Incentive Pay* – Has the Company demonstrated that its proposed incentive pay tracker mechanism is a reasonable alternative to immediately refunding unpaid incentive compensation amounts to ratepayers?

[8] *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).

- *Ratepayer Supplied Funds* – Is MERC's adjustment to ratepayer supplied funds in the amount of $71,159 reasonable?

- *Non-Fuel Operating and Maintenance Expenses* – Are MERC's proposed non-fuel Operating and Maintenance Expenses reasonable, prudent, and otherwise eligible for rate recovery?

- *Construction Work in Progress* – Is the Company's proposed $914,913 rate base addition for Construction Work in Progress reasonable, prudent, and otherwise eligible for rate recovery?

- *Property Tax* – Is the Company's proposed property tax expense increase reasonable, prudent, and otherwise eligible for rate recovery?

- *Purchased Gas Adjustment Consolidation* – Should the Company be required to phase in any consolidation of the purchase gas adjustments currently applicable to its different rate areas?

- *Uncollected Conservation Cost Recovery Charge Revenues* – What is the proper remedy for a Company error that caused it to underfund its Conservation Improvement Program tracker account?

- *Work Asset Management and PeopleSoft Expense* – Has MERC demonstrated that the costs of implementing Work Asset Management and upgrading PeopleSoft are reasonable, prudent, and otherwise eligible for rate recovery?

- *Bad Debt/Uncollectable Expense* – Has MERC demonstrated that its proposed bad debt expense is set at a level that is reasonable and prudent?

- *Regulatory Asset/Cloquet Plant Amortization* – Is MERC's amortization of the Cloquet power plant properly included in rate base as a regulatory asset?

- *Employee Compensation* – Should MERC's employee compensation expenses be reduced across the board as excessive?

Rate Design Issues

- *Residential and Small Commercial and Industrial Customer Charges* – What are the appropriate levels of customer charges for the Residential and Small Commercial and Industrial customer classes?

III. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held three days of evidentiary hearings and three public hearings. He reviewed the testimony of 24 expert witnesses and examined some 128 exhibits. He made 479 findings of fact and conclusions of law and made recommendations on all stipulated and contested issues based on those findings and conclusions.

Having itself examined the record and having considered the report of the Administrative Law Judge, the Commission concurs in most of his findings and conclusions. On a few issues, however, the Commission reaches different conclusions, as delineated and explained below. On all other issues, the Commission accepts, adopts, and incorporates his findings, conclusions, and recommendations.

Issues disputed among the parties or otherwise requiring Commission action are addressed below.

IV. The Pilot Decoupling Program

A. Introduction and Background

The Next Generation Energy Act, enacted by the Minnesota Legislature in 2007, establishes a statewide energy savings goal of 1.5% of annual retail electric and gas sales through energy efficiency.[9] Minn. Stat. § 216B.2401 identifies two direct means of achieving the energy savings goal – through energy conservation improvement programs (CIP), and through rate design. "Decoupling" is one example of a rate design mechanism that is expressly provided for in the Act. The Act allows utilities to implement pilot projects to try decoupling the utility's revenue from changes in energy sales to encourage the utility to promote more conservation.

The Act directed the Commission to establish criteria and standards by which decoupling could be adopted by the state's rate-regulated utilities. In addition, the legislation authorized the Commission to allow one or more utilities "to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation," subject to the criteria and standards that the Commission will have established.

Minn. Stat. § 216B.2412 states that decoupling is "a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency." Specifically, decoupling takes aim at one of the critical barriers to increased investment in cost-effective energy efficiency and other clean energy resources located "behind the customer's meter," namely, the potentially deleterious impacts that such investment can have on utility finances under traditional cost-of-service regulation. Other key goals for decoupling expressed in the statute are to achieve energy savings[10] and not adversely affect ratepayers.[11]

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[9] In 2009, the legislature enacted the Omnibus Energy Bill (Chapter 110), which included a provision allowing natural gas utilities a ramp-up period for energy savings in their 2010-2012 Triennial Plans – with a goal of 0.78% annual energy savings until 2012, and 1.0% annual savings thereafter.

[10] This goal is most directly indicated in Subd. 3 of the statute. In describing pilot decoupling programs, the statute states in part: "Each pilot program must . . . be designed to determine whether a rate-decoupling strategy achieves energy savings."

[11] This goal is stated in Subd. 2 of the statute. In describing the criteria and standards that the Commission is required to design for decoupling programs, the statute indicates that the purpose of the criteria and standards is to ". . . mitigate the impact on public utilities of the energy-savings goals under section 216B.241 without adversely affecting utility ratepayers." (Emphasis added.)

To fulfill its obligation to develop criteria and standards for decoupling, the Commission sought the advice of the Regulatory Assistance Program (RAP).[12] After a series of meetings with regulators and stakeholders, RAP produced a report in June 2008.[13] The RAP Report describes and explores three types of decoupling mechanisms: "full," "partial," and "limited." The Report discusses issues associated with decoupling, alternatives to decoupling, decoupling programs in other states, and the mechanics of decoupling.

The Commission issued an Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling in June 2009.[14] In that Order, the Commission asked utilities to file notice of whether they would file a proposed decoupling pilot program by June 1, 2010. MERC filed its notice of intent to file a decoupling proposal on May 27, 2010.

In 2010 the Commission approved its first pilot decoupling program pursuant to Minn. Stat. § 216B.2412 -- a partial decoupling program for CenterPoint Energy (CenterPoint), in which CenterPoint excludes the impact of weather on sales from its revenue decoupling calculations.[15] The CenterPoint decoupling mechanism was approved by the Commission in CenterPoint's 2010 general rate case.[16]

In this rate case, MERC has proposed a full revenue decoupling mechanism (RDM). A full decoupling mechanism is a revenue true-up technique to recover apportioned class revenue responsibility. The true-up reduces or increases rates charged to classes of customers if their collective usage during a given time period deviates from a set base amount. The mechanism is considered a full decoupling mechanism because the true-up amount is based on deviations from forecasted revenue for any reason, including weather, that differs from forecasted amounts.

B. The Proposed Full Decoupling Proposal

1. MERC

MERC has proposed a three-year pilot program to implement a full decoupling mechanism in the rates charged to its Residential and Small Commercial/Industrial rate classes. MERC explained that its proposed RDM will separate (or decouple) MERC's revenues from the volume of gas it sells, thus removing the financial disincentive to promote energy efficiency and allow MERC the opportunity to collect its approved revenue requirement.

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[12] RAP is a non-profit organization that provides policy and technical assistance to regulators on a range of matters relating to economic and environmental sustainability of the regulated natural gas and electric sectors.

[13] *Revenue Decoupling: Standards and Criteria*, Docket No. E,G-999/CI-08-132 (June 30, 2008).

[14] Docket No. E, G-999/CI-08-132 (June 19, 2009).

[15] Under its approved tariff, CenterPoint is allowed to true up under-recovered revenues unrelated to weather up to 3% below the base revenue amount and must return all over-recovered revenues unrelated to weather.

[16] *In the Matter of the Application of CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1075 (January 11, 2010).

MERC asserted that its RDM uses a symmetrical revenue true-up mechanism -- its proposed RDM is designed to adjust on a per customer basis for sales volumes that are above or below the approved sales levels for each rate group (composed of the applicable rate classes), that is used to determine the volumetric distribution charges approved by the Commission.[17] MERC explained that the true-up mechanism either decreases or increases rates charged to classes of customers if their collective usage during a given time period deviates from a set base amount. The true-up amount, as proposed, is based on deviations from forecasted revenue for any reason (including weather).

MERC proposed that the RDM be determined separately for the two rate classes proposed, and be applied to all customers in each class. MERC also proposed to calculate the RDM adjustments for three calendar years plus any partial calendar year during which the RDM is effective.

MERC stated that during the course of the evidentiary proceedings, it agreed to certain modifications to its RDM mechanism, which were proposed by the Department. MERC argued that as modified, its RDM proposal fully meets the criteria set forth in the decoupling statute, in that its proposal 1) reduces MERC's disincentive to promote energy efficiency; 2) is designed to determine whether a decoupling strategy achieves energy savings; and 3) will not adversely impact ratepayers.

MERC asserted that its proposal meets the first statutory criterion, as the Company will not make more money through additional sales of energy. MERC asserted that the second criterion is met by its agreement to commit to an evaluation plan similar to the one approved by the Commission for CenterPoint's decoupling program.

With respect to the third criterion, MERC stated that it has accepted the Department's proposed recommendations and conditions to the RDM made at the evidentiary hearing, as set forth below, which address concerns regarding ratepayer impact.

2. The Department

Over the course of the evidentiary proceeding, the Department and MERC came to agree on appropriate parameters around which to condition the full pilot decoupling program proposed. The conditions ultimately agreed to by MERC and the Department include the following:

1) the imposition of a 10% symmetrical cap on revenues generated through the application of the RDM;
2) the requirement that MERC use an evaluation plan similar to that used by CenterPoint in its decoupling program;

[17] MERC's proposed RDM calculates the difference between the baseline annual distribution revenues per customer for the rate group approved in the most recent rate case proceeding and the actual annual distribution revenues per customer for the rate group. MERC explained that this difference will be multiplied by the average number of customers that were used to establish charges in the most recent general rate case proceeding to determine the dollar amount that will be collected from, or refunded to, customers. The amount will be recovered or refunded on a per therm basis over a twelve-month period.

3) the requirement that the RDM adjustments be calculated and adjusted on an annual basis;
4) the requirement that MERC calculate the RDM adjustment factor based on the Department's proposal to use class revenue requirements after removing the fixed charge portion and CCRC revenues from the final revenue apportioned to the customer class, and to use the actual 2011 customer count (in lieu of the forecasted customer count, subject to the results of the audit of MERC's billing system);[18] and
5) clarification that the Commission may modify the rates in the pilot if warranted by unexpected circumstances.

The Department and the Company also agreed that the pilot decoupling proposal should not be extended to MERC's large customers. Department witness Christopher Davis stated that the Department needed to fully and systematically analyze the effects of decoupling on large customer classes before it could support application of the RDM to those classes. With MERC's agreement to commit to these additional conditions, the Department recommended that the Commission approve the proposed pilot decoupling program.

C. Positions of the Parties

1. IWLA/MCEA

The IWLA/MCEA supported MERC's request for a full revenue decoupling pilot program, as long as the Commission requires MERC to demonstrate annual incremental progress toward achieving the annual 1.5% annual energy efficiency savings goal set by the Legislature in Minn. Stat. § 216B.2401.

2. OAG

The OAG recommended that MERC's decoupling proposal not be approved by the Commission. The OAG objected to decoupling, and full decoupling in particular, as a radical departure from traditional regulatory principles, by guaranteeing to the utility an unvarying level of revenue rather than the traditional opportunity to earn its authorized rate of return. The OAG argued that MERC has not shown that its proposed full decoupling proposal could be implemented without "adversely affecting utility ratepayers," as required by Minn. Stat. § 216B.2412.

Nor, the OAG argued, has MERC shown that decoupling would increase either energy savings or decrease use per customer beyond that which is required by law. The OAG argued that MERC's decoupling proposal is not in the public interest, as MERC has not established that its RDM would either be good for its customers or the best way to promote additional, incremental energy efficiency. The OAG raised the following arguments in support of its position.

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[18] As explained more fully in the Sales Forecast section of this Order, MERC has agreed to, and is currently in the process of conducting a full billing system audit. The data existing after this full audit will be used to calculate the RDM, based on any corrections from this audit to MERC's original forecast.

First, the OAG asserted that there is no reason for decoupling utility natural gas rates today, or in the foreseeable future, because the current supply environment has made natural gas plentiful and low natural gas prices have made conservation uneconomic. The OAG argued that revenue decoupling adds an unnecessary layer of artificial and complex pricing to currently low natural gas prices.

Second, the OAG argued that revenue decoupling has little if anything to do with energy conservation, absent a clear commitment from the Company to tangible investments in energy conservation and energy efficiency that will produce benefits that are above and beyond what is already required by statute. Absent such a commitment, the OAG argued that revenue decoupling is just a revenue stabilization mechanism that provides the Company with a guaranteed income stream.

Third, the OAG asserted that if the Commission grants MERC decoupling, the RDM should apply to all customer classes, to ensure that the Company will fully embrace a culture that accepts and promotes energy conservation and energy efficiency. The OAG argued that application of the RDM to only two customer classes essentially bifurcates the Company, with one part of the Company essentially indifferent to the level of sales, while the other part (serving large customers) continues to have the traditional incentive to promote the sale of gas.

Fourth, the OAG argued that MERC's super large volume and flexible rate customers are not already decoupled, as asserted by the Department in its rebuttal testimony. The OAG agreed that the throughput incentive for MERC's large customers may not be the same due to various rate design considerations, but argued that the real reason for the exemption of large customers is that their usage is tied to economic conditions.

Finally, the OAG argued that the public comments received show that MERC's ratepayers oppose the Company's proposed decoupling proposal. The OAG stated that adoption of the full decoupling proposal could taint ratepayers' attitudes towards conservation by sending a discouraging price signal for conservation in the form of increased rates to residential and small business customers. The OAG stated that decoupling penalizes rather than rewards customers who conserve by increasing rates to compensate the Company for the reduction in sales due to conservation.

3. Super Large Gas Intervenors

The Super Large Gas Intervenors (SLGI) opposed the OAG's recommendation that MERC's revenue decoupling mechanism be modified to include all customers, and objected to the OAG's recommendation that the decoupling pilot program should include the SLGI group. SLGI argued that there are three reasons to exclude the SLGI group from the pilot program:

1) the members of SLGI do not buy energy from MERC and are therefore statutorily excluded from the definition of decoupling;
2) Commission precedent favors excluding customers such as SLGI from a decoupling program;

3) the Department acknowledged that SLGI's rates may already be essentially decoupled via rate design; and most of the SLGI members are CIP exempt and therefore excluded from MERC's conservation and efficiency programs – the alleged programs requiring a decoupling program in the first place.

Thus, SLGI argued that there is no justification for including SLGI in any approved decoupling program.

D. Recommendations of the Administrative Law Judge

The ALJ concluded, based on a thorough review of the record, that MERC's revenue decoupling mechanism and proposed pilot program meet the requirements of Minnesota law and previous Commission Orders on decoupling, and are based on sound ratemaking principles. The ALJ concluded that the RDM should be computed annually, applied to the Residential and Small C&I rate groups, contain a symmetrical 10% cap on RDM revenues, and run for three full calendar years.

The ALJ recommended that the Commission require MERC to submit an annual evaluation plan similar to the one used in CenterPoint's decoupling pilot, and to file annual reports to the Commission that specify the RDM adjustment to be applied to each rate class for the billing period demonstrating annual progress toward achieving the 1.5% energy efficiency goal set in Minn. Stat. § 216B. 241.

E. Commission Analysis and Action

The Next Generation Energy Act specifically directed the Commission to approve one or more pilot decoupling programs to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation. After careful consideration of the testimony and evidence submitted in this case, the Commission will accept and adopt the findings and conclusions of the ALJ to authorize MERC to implement a full revenue decoupling pilot program, with the modifications and conditions set forth below.

The Commission finds that MERC's proposed full revenue decoupling mechanism meets the Legislature's directive for a decoupling program by separating the Company's sales from revenues, in order to remove the disincentive for the Company to pursue conservation, while not adversely impacting ratepayers.

The Commission further finds that MERC's proposed full revenue decoupling program satisfies the statutory requirements of Minn. Stat. § 216B.2412.[19] The Commission finds that MERC's proposed full decoupling program meets the first statutory criterion to remove a utility's disincentive to increase energy savings because, under the proposal, MERC will not make money through additional sales of energy.

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[19] Minn. Stat. § 216B. 2412 states that a decoupling mechanism must 1) reduce a utility's disincentive to promote energy efficiency; 2) be designed to determine whether a rate-decoupling strategy achieves energy savings; and 3) not adversely affect ratepayers.

The Commission finds that MERC's decoupling proposal also satisfies the second statutory criterion, by the Company's agreement to commit to an evaluation plan similar to the one previously approved by the Commission for CenterPoint's pilot decoupling program.

Third, the Commission finds that MERC's decoupling proposal, as modified by the agreements and conditions ultimately reached by MERC and the Department, satisfies the statutory criterion that a decoupling mechanism not adversely affect ratepayers. As noted by the ALJ, and as set forth in the Commission's Standards,[20] all utility pilot proposals must be reviewed yearly. Importantly, if warranted by unforeseen circumstances, the parties recognize that the Commission has the authority to modify or suspend the rates in the pilot program, and the Commission conditions its approval of the pilot program on MERC stating in its RDM tariff that the Commission has such authority.

Further, with the agreed-upon 10% symmetrical cap on revenues generated through the application of the RDM, and assuming an average annual use of 85 Mcf, the maximum revenue decoupling adjustment for an average residential customer will not exceed $21 (more) per year. With these conditions limiting ratepayer impact, the Commission finds that MERC's RDM should not adversely affect ratepayers.

Having found that MERC's proposed RDM meets the statutory criteria, the Commission approves MERC's request for a full revenue decoupling pilot program in the form recommended by the ALJ, but with the modifications or conditions set forth herein.

1. The OAG's Objections to the Program

In reaching its decision to approve the Company's pilot decoupling proposal, the Commission has carefully considered the arguments, objections, and proposed modifications to MERC's full decoupling mechanism raised by the OAG throughout this proceeding.

While the Commission recognizes that the current supply environment has reduced natural gas prices, this fact does not counterbalance the Legislature's clear directive that the Commission authorize one *or more* decoupling pilot projects, to assess the merits of rate-decoupling to promote energy efficiency and conservation.

MERC's proposal for a pilot program, using a full decoupling mechanism, differs significantly from CenterPoint's ongoing partial decoupling program, and will provide additional and valuable data from which the Commission can assess the merits of decoupling in today's complex energy environment.

2. Energy Conservation

Further, while the OAG asserts that absent a clear commitment from MERC to undertake an increased level of investment in energy conservation, its decoupling proposal is simply a revenue stabilization mechanism, the Commission does not agree. MERC has committed to, and is in fact

[20] *In the Matter of a Commission Investigation into the Establishment of Standards and Criteria 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, at 8, paragraph 7 (June 19, 2009).

achieving, energy saving that far surpasses its historical rates.[21]

As evidenced by the testimony of Department witness Christopher Davis, MERC has made steady progress toward reaching the Next Generation Energy Act's 1.5% energy saving goal, and has implemented the infrastructure and policies needed to increase and sustain its CIP. The IWLA/MCEA recommended that the Commission approve MERC's request, but on the condition that MERC demonstrate incremental progress toward achieving the annual 1.5% annual energy efficiency saving goal established by the Legislature in Minn. Stat. § 216B.241.

The Commission concurs. The Commission recognizes that MERC may already have plans in effect to achieve a higher level of energy savings in its upcoming triennial CIP filing. However, to ensure that the implementation of decoupling does not hamper MERC's continued progress toward attaining the 1.5% savings goal, the Commission will condition approval of the revenue decoupling program on MERC making a demonstration of annual incremental progress towards achieving a 1.5% rate of annual energy savings.

Accordingly, the Commission will require the Company to file annual reports to the Commission that specify the RDM adjustment to be applied to each rate class for the billing period and demonstrate annual progress toward achieving the 1.5% energy efficiency goal set forth in Minn. Stat.§ 216B.241.

3. Inclusion of Additional Classes

The OAG also argued that if the Commission approves MERC's full decoupling proposal, the Commission should apply the proposed RDM to all customer classes, and not just the Residential and Small Commercial/Industrial rate classes.

The Commission concurs with the ALJ, who adopted the rationale of the Department in excluding the larger rate classes from MERC's decoupling proposal. While the Department initially agreed with the OAG that the RDM should apply to all customer classes (to remove the utility's disincentive to implement energy conservation programs for those customers), at the evidentiary hearing the Department recommended that the large customer classes not be included in the pilot decoupling proposal, because of the structure of the rate design in those classes. The Department stated that it needed to fully and systematically analyze the effects of decoupling on large customer classes before it could recommend that the RDM be applied to them.

The Commission agrees that the rates for MERC's large customer classes do not include the same throughput incentive as rates for the smaller customer classes. Further, as recognized by the ALJ, there could be adverse impacts on customers if the RDM were applied to all customer classes as proposed by the OAG. MERC's large customer groups have dissimilar usage patterns, and are sensitive to economic conditions and service interruption. As noted by the ALJ, unlike the customer classes included in MERC's proposal, if one large customer's usage were to decline based upon economic or customer-specific conditions, or one or more customer's usage is interrupted, the

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[21] MERC-PNG's and MERC-NMU's current combined goal of achieving energy savings is equal to 1.03% of retail sales – the two utilities' combined energy savings in 2007 was 0.26%.

remaining customers could be assessed a surcharge, which could be substantial if the class included only a small number of customers.

Finally, excluding the large customer classes from the application of the RDM is consistent with precedent from the Commission's decision in the CenterPoint rate case proceeding.[22] In the CenterPoint decision, the Commission found that exclusion of the Company's larger customer classes from the CenterPoint's decoupling proposal was reasonable, because the usage in those classes is more closely tied to general economic conditions than the firm sales classes.

Having considered the issue as presented by the parties herein, the Commission concludes that it is reasonable and appropriate to exclude these customer groups from the pilot proposal due to their different economic circumstances and the need for additional examination and analysis as to the effects of decoupling on large customer classes.

4. Other Actions

In conclusion, the Commission approves the pilot decoupling program, as modified herein, effective with the implementation of final rates in this proceeding, for a period of no more than three years (thirty-six months) unless extended by Commission action. The Commission will require the Company to adhere to the following conditions in implementation of the RDM:

1) MERC shall use the same billing determinants (customer counts, etc.) used to set final rates to determine the RDM baseline;
2) MERC shall use its initial sales forecast, corrected only as needed to resolve any errors discovered in the Vertex billing audit in favor of ratepayers, for decoupling purposes;
3) MERC shall explain its revenue decoupling program in its notice to customers about final rates at the end of this case and in another notice when the first annual revenue decoupling rate adjustment is implemented on customer bills;

As part of its thirty-day rate case compliance filing, the Commission will require MERC to submit the following: 1) a proposal for implementing its RDM mechanism mid-year, including prorated RDM baseline calculations for the part of the year MERC expects the RDM to be in place at the beginning of the program and at the end of the program; and, 2) revised revenue decoupling tariff language that incorporates all of the Commission's decisions in this docket.

Approval of MERC's decoupling proposal will provide valuable data on whether an alternative form of rate decoupling – full decoupling – achieves continued and/or additional energy savings for the utility. No pilot program can guarantee a particular result in advance. The decoupling statute, however, does not require such a guarantee as a precondition for approving a pilot program.

[22] Docket No. G-008/GR-08-1075 (January 11, 2010).

V. Return on Equity

A. Introduction

In determining 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*." Minn. Stat. § 216B.16, subd. 6, emphasis added.

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 MERC is a wholly-owned subsidiary of Integrys Energy Group 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 two parties who conducted full cost-of-equity studies – the Company and the Department – based their analysis on comparison groups of utilities they considered similar enough to MERC to serve as proxies in determining the Company's cost of equity. While the two comparison groups were not identical, they were very similar, with six of the same companies appearing in both the Department's eight-company group and MERC's seven-company group. Consequently, the most significant differences between the two parties' analyses and outcomes did not result from differences in their comparison groups, but from other philosophical and methodological differences.

Both the Company and the Department 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, due to a history of producing volatile and unreliable outcomes.

The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities by determining the net present value, or price per share, of a company's stock. 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 historical 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 by equity holders over various historical periods.

B. Positions of the Parties

MERC recommended a return on equity of 10.75%. That number was derived by applying all three analytical models discussed above to each company in MERC's comparison group, synthesizing the results to arrive at a baseline return on equity, adding an adjustment for flotation costs,[23] and adjusting the final figure upward to reflect industry-wide, time-specific, and company-specific factors that the Company believed increased its business risk.

The Department recommended a return on equity of 9.41%. That number was derived by completing a DCF analysis on each company in the Department's comparison group and evaluating the range of results in light of two secondary resources – the range of the Department's CAPM results and the range of the 26 most recent cost-of-equity determinations made for natural gas utilities by state public utilities commissions. The Department, like MERC, added a flotation adjustment to the final figure.

The OAG did not recommend a specific return on equity and did not conduct a full cost-of-equity analysis. It did, however, oppose including flotation costs in the cost of equity, both on principle and on grounds that the flotation costs claimed in this case were inflated. Finally, the OAG argued that the Commission should reduce the Company's return on equity if it approved the Company's proposal to decouple revenues from changes in energy sales, since decoupling would reduce business risk.

The parties' positions are further described below.

1. MERC

MERC recommended a return on equity of 10.75%, which it derived by applying all three analytical models to each company in its comparison group, synthesizing the results, adding a flotation adjustment, and adjusting the final figure upward to reflect industry-wide, time-specific, and company-specific factors that the Company believed increased its business risk.

MERC argued that the DCF analytical model – the one the Commission has generally found most trustworthy and relied upon most heavily – is not a reliable tool for determining the cost of equity in this case. The Company pointed to two features of the model that allegedly render it unreliable.

First, the model is somewhat circular; it involves a regulatory agency setting rates of return based on investors' expectations, which are themselves based on rates of return set by other regulatory agencies in earlier cases. This is a structural limitation, and the Company made no adjustment to its DCF results to reflect this feature of the model.

Second, the model does not take into account the disparity between the book value at which utility assets are valued and on which regulators base authorized returns, and the market values investors typically perceive and rely on in making their investment decisions. This disparity, the Company

[23] Flotation costs are the fees and expenses a company incurs to issue securities.

argued, understates and under-compensates for risk by making utilities' debt ratios appear lower than they are. The Company made a 0.61% upward adjustment to its DCF results to account for this feature, calling it a "leverage adjustment."[24]

The Company argued that its cost of equity could be determined more accurately by using all available analytical models – the DCF, the CAPM, and the Risk Premium – and synthesizing the results, rather than working from the model thought to be most reliable and treating the others as secondary, as the Department did. The Company pointed out that all models have strengths and weaknesses, and argued that treating all three models as equally probative would yield a more accurate result by tapping all models' strengths and permitting their weaknesses to offset one another.

The Company also argued that the cost of equity should be adjusted upward to account for risk factors not adequately accounted for in the models, some industry-wide and some MERC-specific. The two industry-wide risk factors were the book value/market value dichotomy discussed earlier, and the market volatility and uncertainty resulting from the current economic downturn.

The MERC-specific factors were the relatively small size of the Company, its significant concentration of large industrial customers (who are subject to competitive pressures and may be able to bypass the Company's system), and the Company's relatively high earnings variability, relatively low interest coverage, and relatively high five-year average operating ratio. None of these risks were easily quantifiable, and adjusting for them required the exercise of professional judgment and expertise.

2. The Department

The Department recommended a return on equity of 9.41%. That number was derived by completing a DCF analysis on each company in the Department's comparison group and evaluating the range of results in light of two secondary resources – the range of the Department's CAPM results and the range of the 26 most recent cost-of-equity determinations made for natural gas utilities by state public utilities commissions, as reported by *Public Utilities Fortnightly*'s online database. The Department, like MERC, added a flotation adjustment to the final figure.

The DCF results for the companies in the Department's comparison group ranged from 7.40% to 9.41%, with a median of 8.52%. The Department recommended setting MERC's cost of equity at the level of its highest DCF result, 9.41%, because its secondary, corroborating sources (its CAPM analysis and *Public Utilities Fortnightly*'s online database) trended toward the higher end of the range.[25]

The Department strongly recommended basing the Company's cost of equity on the DCF analytical model and using the other models mainly as reasonableness checks. The agency stated that it used the DCF model because that model has proved to be the most trustworthy over the decades, is more transparent and objective than the other two models, and has been relied upon more consistently by the Commission.

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[24] Ex. 23 at 14 (P. Moul Rebuttal).

[25] Exhibit 26 at 6-10 (Griffing Surrebuttal).

The Department rejected MERC's claims that its cost of equity should be adjusted upward to account for its size, the book value/market value dichotomy for which it requests a leverage adjustment, the potential for market volatility inherent in the current economic downturn, its reliance on large industrial customers, or any of the company-specific financial factors cited (interest coverage, earnings variability, operating ratio).

The agency stated that the leverage adjustment was unnecessary because investors are not markedly unsophisticated, and the book value-market value dichotomy is a fundamental and enduring feature of utility stocks. Similarly, the Department opposed an upward adjustment for the uncertainty created by the economic downturn, arguing that that uncertainty was being felt throughout the economy and would assuredly be reflected in the stock price and dividend inputs of the DCF model. Further, the agency cautioned that regulated monopolies providing essential services were not subject to the same uncertainties as other private-sector businesses.

The agency argued that no adjustment was needed for the Company's size, heavy concentration of large industrial customers, or any of the company-specific financial factors cited, because the integrity of the comparison group – made up of companies with diverse characteristics but similar business models, capital structures, and credit ratings – ensured that individual differences would offset one another and be neutralized by the companies' overarching similarities.

Further, the Department pointed out that it did not make – and the Company did not recommend – a downward adjustment to the cost of equity to reflect the impact of the decoupling initiative proposed by the Company. Decoupling revenues from gas sales would increase revenue stability and reduce business risk, and the agency argued that, if the cost of equity were adjusted for company-specific risk factors, decoupling should prompt a downward adjustment.

3. The OAG

The OAG did not conduct a full cost-of-equity analysis, but it did oppose including flotation costs – the costs of issuing securities – in the cost of equity, citing three reasons.

First, the OAG claimed that the flotation cost number accepted by the Company and the Department was too imprecise to support rate recovery. (Since MERC has no publicly traded stock, the Company and the Department agreed to use a proxy number, 4%, the average cost of public offerings of common stocks by natural gas utilities from 2003 to 2008.) Second, the OAG claimed that the proxy number was inflated by failing to exclude no-cost or low-cost, non-public securities issuances from the calculation. And third, the OAG claimed that the proxy number included an acquisition premium and transaction costs the Company was prohibited from recovering under the Commission order permitting its parent company to purchase the company that is now MERC.[26]

Finally, the OAG argued that the Commission should reduce MERC's return on equity if it approved the Company's proposal to decouple revenues from changes in energy sales, since decoupling would reduce business risk.

[26] *In the Matter of the Sale of Aquila, Inc.'s Minnesota Assets to Minnesota Energy Resources Corporation*, Docket No. G-007,011/M-05-1676, Order Approving Sale Subject to Conditions (June 1, 2006).

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge conducted a lengthy analysis of the parties' arguments and concluded that in this case the DCF analytical model was "far superior" to the multiple-model approach urged by MERC, because the DCF model minimizes analyst discretion and analyst opportunity to influence the model's results.[27] He found that the CAPM, Risk Premium, and Comparable Earnings models (the third used only by the Company, and only as a reasonableness check) were all highly dependent on analyst discretion for nearly every input.[28]

He noted that, at least in regard to the Company's proposed upward adjustments for its relatively small size and the book value/market value dichotomy, its cost-of-equity analysis was essentially identical to the cost-of-equity analysis the Commission rejected in its last rate case.[29] He found that no downward adjustment was required to account for the Company's proposed decoupling program, which was already reflected in the composition of the comparison group.[30] He recommended rejecting the Company's multi-model analysis in favor of the Department's objectively supported recommendation.

He concurred with the Company and the Department that flotation costs must be taken into account in setting the cost of equity to permit the Company the opportunity to earn its full rate of return.[31] Ultimately, he recommended adopting the 9.41% return on equity recommended by the Department for the reasons set forth by the Department.

D. Commission Action

The Commission concurs with the Administrative Law Judge on this issue and accepts, adopts, and incorporates his findings, conclusions, and recommendations, with one modification. The Commission will remove one company whose DCF results may well be anomalous from the DCF comparison group, raising the return on equity from the Department's recommended 9.41% to 9.70%. These decisions are explained below.

1. The Analytical Models

First, as it did in MERC's last rate case, the Commission rejects the Company's claim that using three models to determine return on equity is superior to relying primarily on the strongest model and using others as validity checks.[32] As the Commission explained in that case:

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[27] ALJ's Report, ¶¶ 127 and 128.

[28] ALJ's Report, ¶¶ 123 – 128.

[29] ALJ's Report, ¶ ¶ 107, 120.

[30] ALJ's Report, ¶ 96.

[31] ALJ's Report, ¶ 85.

[32] *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-007, 011/GR-08-835, Findings of Fact, Conclusions of Law, and Order (June 29, 2009).

> The Commission rejects the Company's claim that using three models to determine return on equity is inherently more accurate than relying primarily on one, with a second serving as a validity check. It is not the number of models in the record that ensures a sound decision, but the appropriateness of each model for the purpose at hand, the quality of the data selected as inputs, and the caliber of the analysis applied to the results. Using three models does produce a more detailed record, but it also multiplies the risk of inaccurate inputs and increases the number of points at which subjective judgments are required.
>
> In short, not all models are equally probative, and not every application of the same model is equally probative. The Commission examines the results of every model introduced into the record in every case. In this case the DCF model is the best in the record for determining return on equity.[33]

Here, too, the Commission finds that the transparency and objectivity of the DCF model make it the strongest, most credible model, and that the most reasonable way to proceed is to use its results as a baseline and to use the results of other models to check, inform, and refine those results.

As the Department and the Administrative Law Judge concluded, the DCF model calls for fewer subjective judgments than the CAPM and Risk Premium models – in fact, two of its three inputs, dividends and market equity prices, are uncontested, publicly reported facts, and the third input, projected growth rates, generally come from a limited number of recognized professional resources. (In this case, both parties turned to the same three professional resources: Value Line Investment Survey, Zacks Investment Research, and Yahoo! Finance.)

The CAPM and Risk Premium methods, on the other hand, require expert judgment at nearly every turn – determining the term of the risk-free, interest-bearing investment used as a benchmark, determining the time frame for calculating growth rates, determining the beta that represents market volatility, determining the historical periods over which to measure returns. Almost none of these inputs are simple matters of fact and public record.

Further, the Company's three-model method compounds the subjectivity in each of the three models by requiring the analyst to synthesize their results, using subjective criteria. It is much more straightforward to choose the strongest model, use its results as a baseline, and use the results of the other models as additional information.

2. Risk Adjustments Sought by the Company and the OAG

Second, the Commission rejects the Company's and the OAG's claims that the return on equity must be adjusted upward or downward to reflect risk factors – generic and MERC-specific – allegedly not adequately represented by the companies in the comparison group.

Neither of the two generic factors cited by the Company – the economic downturn and the book value/market value dichotomy – merits an adjustment. While the economic downturn may be causing some market volatility and uncertainty, those conditions prevail throughout the economy and are therefore reflected in in the stock price and dividend inputs of the DCF model. Further, as a

[33] *Id.* at 13.

regulated monopoly providing essential services, MERC is likely subject to less uncertainty and volatility than other private-sector firms.

Similarly, the book value/market value dichotomy does not require or merit an upward adjustment. As the Commission explained in MERC's last rate case:

> Such an adjustment would have to rest on the erroneous assumption that investors buying utility stocks are ignorant of one of the most basic facts of utility regulation – that book value is the norm for pricing utility assets and that returns will be based on book value. Assuming that investors know this basic fact, which they must, since they keep buying utility stock, the only reasonable assumption is that the market value/book value dichotomy is reflected in the stock price. The stock price, of course, is properly factored into the DCF model, making further adjustment unnecessary.[34]

Nor would it be appropriate to adjust the Company's cost of equity to reflect the MERC-specific factors cited by the Company – its size, its significant concentration of large industrial customers, or any of the financial factors cited (interest coverage, earnings variability, operating ratio). As the Department and the Administrative Law Judge pointed out, any characteristic important enough to affect risk would have been recognized and taken into account by Standard and Poor's in assigning the Company's credit rating, a critical determinant in assembling the comparison group. Making an additional adjustment would amount to counting the characteristic twice.

Further, it would disrupt the workings of the DCF model by inserting subjective judgments at a stage that is normally free of them. It would obligate analysts trying to determine MERC's cost of equity to conduct detailed factual analyses to identify company traits that might increase or decrease its risk.

The Company's decoupling pilot project, for example, reduces business risk by stabilizing revenues and might therefore warrant a reduction in the cost of equity under the Company's theory; the OAG claimed that it does. The size of any adjustment could only be determined by exhaustive comparisons between MERC's decoupling project and the diverse revenue-stabilization measures in use by the companies in the comparison group. It is highly improbable that the additional complexity and subjectivity this analysis would bring would increase accuracy beyond that provided by relying on the integrity of a properly assembled comparison group.

3. Flotation Adjustment

The Administrative Law Judge concurred with the Company and the Department that flotation costs are properly added to the cost of equity to ensure the Company an opportunity to earn its full, authorized rate of return. He also found that the 4% level agreed to by those parties was just and reasonable. The Commission concurs.

It is clear that raising equity capital involves substantial costs. If these costs are not factored into the cost of equity, or an equivalent adjustment made, the amount of equity available for Company use would be overstated and its ability to earn its authorized rate of return impaired. In effect, the

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[34] *Id*. at 15.

Company would be granted a lower rate of return than the one officially set by the Commission. A flotation cost adjustment is therefore just and reasonable.

The Commission also concurs with the Administrative Law Judge that the 4% figure proposed by the Company and the Department is just and reasonable. That figure is the average flotation cost for publicly traded stock issued by public utilities similar to MERC; it does not include privately issued equity or any securities other than publicly traded stock.[35]

4. Modification to Department's Cost of Equity

Finally, while the Commission concurs with the Administrative Law Judge that the Department's cost-of-equity analysis is fundamentally sound and should be adopted in this case, the Commission has one concern about the composition of the comparison group. As a precaution, it will remove one company, New Jersey Resources, to ensure that its potentially anomalous data does not skew the rate of return downward.

Both parties made serious efforts to ensure that the companies in their comparison groups were as similar to MERC as possible in terms of business models, capital structures, and credit ratings. The DCF model rests on the assumption that individual differences between companies in a properly composed comparison group will offset one another and be neutralized by the companies' overarching similarities. It is therefore important that the companies really be similar, and both parties gave careful attention to that issue.

Although both parties included New Jersey Resources in their groups, the Commission is concerned upon further review that the company's DCF inputs – stock prices, dividends, and growth rates – may have been time-lagged and artificially low at the close of the record.

The Department's surrebuttal testimony includes a Value Line report telling of recent developments likely to affect the company's near- and intermediate-term prospects, including a major increase in customer numbers, 23 infrastructure investments totaling over $60,000,000, and a "skyrocketing" cash reserve accompanied by relatively constant debt levels. Further, a new rate case filing is anticipated.[36] These developments are likely to affect the company's DCF factors in the near term, and the Commission is therefore reluctant to include its current DCF inputs among those used to set prospective rates for MERC.

Further, removing New Jersey Resources from the Department's comparison group would still leave a group of seven companies – a valid number for a comparison group – and those companies would be more clearly comparable to one another and to MERC than those in the current group. The Commission will therefore remove New Jersey Resources from the group, to ensure that MERC's cost of equity is not skewed by what may be artificially low DCF results for that company. The resulting cost of equity is 9.70%, and the Commission will set MERC's return on equity at that amount, for all the reasons set forth above.

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[35] Exhibit 22 at Appendix F, F-2 to F-3; Exhibit 22 at Schedule (PRM-1), Schedule 7 (P. Moul Direct).

[36] Exhibit 26, Attachment at 6 (Griffing Surrebuttal).

VI. Sales Forecast

A. Introduction

The Commission requires a reasonable test-year sales forecast as the foundation for determining just and reasonable rates. Test-year sales volumes are important factors in calculating a utility's revenue requirement, rate design, and conservation cost recovery charge because sales levels affect both revenues and expenses. Lower sales levels will result in higher rates since costs would be spread over fewer units.

The issue in this rate case is whether the sales forecast used to set final rates should be the initial sales and revenue forecast for the 2011 test year, as recommended by the Department and OAG, or the revised sales forecast, using the Company's most recent 12-month actual meter counts and actual sales from June 2010 through May 2011, as proposed by the Company.

B. Positions of the Parties

1. MERC

MERC initially proposed its sales and revenue forecast for the 2011 test year. In response to objections from both the Department and the OAG, the Company submitted its revised sales forecast.

MERC stated that its revised forecast addresses the concerns that the Department and the OAG raised regarding MERC's forecasting data. MERC stated that the Department testified to MERC's willingness to work with the parties to satisfy forecasting concerns.

The Company proposed that the revised forecast be used in this rate case because it is composed of actual meter counts and the corresponding non-weather normalized sales for June 2010 through May 2011. While MERC stated that the initial forecast is valid for ratemaking purposes, MERC argued that the record demonstrates that MERC's revised forecast is reasonable and should be used in this rate case.

2. OAG

The OAG recommended that the Commission use the initial sales forecast for this rate case. The OAG argued that test-year sales volumes will also influence revenue apportionment to the various classes because the test-year sales volumes are also used to allocate costs in the Class Cost of Service Study (CCOSS). Additionally, the OAG stated that MERC's initial forecast was weather normalized and MERC's revised forecast was based only on 12 months of actual data.

The OAG stated that MERC's revised sales forecast increases the proposed revenue requirement by $1,893,486 over MERC's initial sales forecast. The OAG stated that the Commission should use the sales forecast that is the least harmful to ratepayers and that it is reasonable to adopt the initial sales forecast. In addition, the OAG pointed out that witnesses from both the Company and the Department agreed that the first sales forecast was acceptable for setting rates in this case.

3. The Department

The Department, after working with the Company, was willing to support MERC's revised sales forecast. In consideration of the OAG's objections to using the revised forecast and arguments in favor of the initial forecast, the Department finally recommended that the Commission use the initial sales forecast data to set rates in this proceeding. The Department recognized that MERC had conceded that the initial sales forecast was adequate for setting rates.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that MERC's initial sales forecast was reasonable and recommended that the Commission use MERC's initial sales forecast for setting rates in this proceeding, noting that using the initial sales forecast would result in a revenue requirement nearly $1.9 million lower than MERC's revised sales forecast.[37]

D. Commission Action

The Commission recognizes the importance of developing an appropriate sales forecast in rate case proceedings. The sales forecast is integral to the appropriate resolution of numerous issues in a rate case, including setting a reasonable and appropriate revenue requirement, allocating costs through the class cost of service study to customer classes, and setting reasonable and appropriate rates.

The issues related to the sales forecasting in this case were complex. The initial sales forecast proposed by the Company was challenged by both the Department and the OAG due to questions about verification of the sales forecasting data utilized. Working in cooperation with the parties, MERC subsequently submitted a revised sales forecast, less comprehensive in scope but based on actual data. Further, the Company agreed to conduct a billing system audit and to revise its sales forecast, and the rates based on its sales forecast, to correct any errors correctable in favor of ratepayers.

The Commission agrees with the Department and the OAG that the initial, weather-normalized sales forecast is the most reasonable basis for setting rates in this proceeding. All parties presented testimony agreeing that that forecast was an appropriate basis for setting rates. That forecast was weather-normalized, prepared in accordance with standard regulatory practice, and constitutes the most straightforward and reliable data in the record. Further, the billing system audit MERC has agreed to perform, discussed in the next section, will provide an additional accuracy check.

Having reviewed the record, the Commission concurs with the ALJ's recommendation and finds that in this case, the appropriate forecast to use is MERC's initial sales forecast, corrected only as needed to resolve any errors discovered in the audit in favor of ratepayers. If no such errors are found, then MERC's initial sales forecast will be used. The Commission clarifies ALJ Proposed Findings 141 and 454 as follows:

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[37] ALJ Report, ¶ 141.

141. The Administrative Law Judge concludes that MERC's initial sales forecast, adjusted if needed to resolve any errors stemming from the audit in favor of ratepayers, is reasonable and recommends that the Commission use MERC's initial sales forecast, adjusted if needed, for setting rates in this proceeding, noting that it will result in a revenue requirement nearly $1.9 million lower than MERC's revised sales forecast.

454. MERC has agreed to, and is currently in the process of conducting a full billing system audit. The data existing after this full audit can be used to calculate MERC's RDM, ~~whether the Commission approves~~ based on any corrections from this audit to MERC's original forecast or the later one.

VII. Billing System Audit

A. Introduction

The OAG and the Department raised concerns about the data used to prepare MERC's initial sales forecast in this proceeding. According to the Department, the billing data included negative sales and customer counts, among other anomalies. MERC agreed to perform an audit of its billing system to address these concerns. Recognizing the proposed audit, the ALJ found that:

> MERC, the Department, and the OAG have agreed that the parties will reach mutual agreement on the use of an external auditor and the scope of the audit on MERC's billing systems. MERC has agreed that if the audit identifies any understatement of the sales and customer counts, the record should be reopened to make any necessary modifications to the final rates in this proceeding.[38]

The parties hoped to complete the audit in time for it to be part of the record prior to oral argument. At the time of oral argument, the audit was underway and expected to be completed at the end of June 2012. At issue is whether the audit is adequate, in light of a misunderstanding concerning the process of arranging the audit.

B. Positions of the Parties

In its exceptions to the ALJ's findings, the OAG contended that MERC had hired a firm to conduct the audit without the OAG's agreement. At oral argument, MERC represented that it mistakenly believed it had reached agreement with the OAG. Upon that mistaken understanding, MERC engaged PricewaterhouseCoopers to perform the billing system audit. The OAG contended, and MERC acknowledged, that PricewaterhouseCoopers has an ongoing consulting contract with MERC. But MERC noted that PricewaterhouseCoopers is not the Company's financial auditor.

The OAG argued that the appearance of a potential for a conflict of interest fatally taints the PricewaterhouseCoopers audit and its eventual results. The OAG advocated that the Commission require a forensic audit by a neutral third party, conducted at the Commission's direction, with the Commission determining its scope.

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[38] ALJ's Report, Finding 134.

The Department did not object to the scope of the audit or the selection of PricewaterhouseCoopers, and believes that the results of the audit should only be incorporated in the rate case record if doing so would benefit ratepayers.

C. The Recommendation of the Administrative Law Judge

Because the ALJ understood that the parties would agree on the firm to conduct the audit, he did not consider or make a recommendation addressing this circumstance.

D. Commission Action

The Commission adopts the ALJ's findings on this issue, and declines to prejudge the results of the audit that is already underway. The efforts of the parties to complete the audit in time to be included as part of the record were unfortunately unsuccessful, but results will soon be available for the parties and the Commission to review. Pursuant to the agreement of the parties and consistent with the ALJ's Finding 135, the audit results will be brought before the Commission and if the audit reveals significant issues with MERC's billing data the inclusion of which would benefit ratepayers in connection with this proceeding, the Commission may reopen the record or take another action it deems necessary.

VIII. Test-Year Pension Expense

A. Introduction

To accurately determine the allowed pension costs in a rate case, the assumptions used to calculate pension costs must be reasonable. The amount of pension expense to be included in rates must reflect the likely or reasonable expense going forward until the next rate case.

MERC's test-year pension expense consisted of the employee pension expense and MERC's share of Integrys Business Support's (IBS)[39] employee pension expense. These expenses were treated separately as (1) A&G Pension Expense, and (2) IBS Employee Pension Expense.

The parties agreed that MERC would remove all but $7,874 of the test year non-qualified pension plan costs from the revenue requirement. This remaining amount was disputed between the OAG and MERC.

The issue in this rate case is whether MERC's proposed pension expense is reasonable, and if not, what adjustments are required.

B. Positions of the Parties

1. MERC

MERC initially proposed a test-year pension expense amount of $1,863,823 for MERC employees, along with approximately $529,830 for MERC's share of pension expense for IBS employees, for a

[39] Integrys Business Support, LLC, is Integrys Energy Group's business services company.

total of $2,393,653. The Department recommended a reduction of $429,927 to MERC's initially proposed pension expense and a reduction of $35,890 to MERC's share of IBS employee pension expense.

MERC's final pension expense proposal for 2011 test year expense included $1,797,228 for MERC employees and $435,798 for IBS employee pension expense.

MERC asserted that a 5.80 percent discount rate was reasonable in the current discount rate market and that MERC's 8.25 percent expected return on assets was supported by record evidence. MERC also argued that its wage assumption rate of 4.50 percent for non-bargaining employees and 4.00 percent for bargaining employees most accurately reflected all factors for wage increases.

2. The Department

The Department disputed several assumptions that formed the basis of MERC's pension expense calculation and argued that MERC's requested amount was too high. The Department stated that the financial markets recovered significantly from December 2009 when MERC's pension expense was calculated. The financial markets showed an increase in the Dow Jones Industrial Average of over 30% from December 2009 to April 1, 2011.

The Department also disputed MERC's initial test-year discount rate, MERC's test-year expected return on plan assets, and MERC's test-year annual rate of compensation increase. The Department argued that MERC's proposal was unreasonable because the Company was proposing that rates be set based on the assumption that its employees provide no contribution to their own pension.

The Department recommended that the Commission find MERC's proposed pension expense unreasonable and overstated. The Department recommended that MERC's pension expense be set no higher than 2010 actual levels, with IBS pension expenses set at 2010 levels.

C. Recommendations of the Administrative Law Judge

The ALJ concluded that MERC has failed to demonstrate the reasonableness of its proposed pension expense.[40] The ALJ further concluded that MERC's updated discount rate of 5.80% is the lowest rate in recent history, 10 basis points lower than its initially proposed 5.90, and 45 basis points lower than the 2007-2010 average of 6.25%, finding that it was not reasonable to set pension expense recovery using such a historically low discount rate.[41] The ALJ found that MERC failed to demonstrate by a preponderance of the evidence that its test year pension expense calculation was reasonable and in the public interest.[42]

The ALJ also found that, based on the Department's and OAG's recommendation, MERC agreed to an adjustment removing the non-qualified pension plan costs in Account 926019, which contains MERC's allocation of IBS costs.

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[40] ALJ Report, ¶ 153.

[41] ALJ Report, ¶ 155.

[42] ALJ Report, ¶ 159.

D. Commission Action

The level of pension expenses that will be paid by the ratepayer is an important issue. Pension expense calculations are done at a specific point in time and can vary from year to year. The Commission's ratemaking function of establishing a reasonable level of pension expense must reflect the likelihood of the expense going forward until the Company's next rate case.

The Commission concurs with the Administrative Law Judge that MERC's test-year pension expense should be no higher than 2010 levels, and the Commission adopts the ALJ Findings 142-164. Additionally, in its next rate case, MERC must fully support the reasonableness of having ratepayers pay for 100% of MERC's pension obligation.

The Commission adopts the ALJ's recommendation on the issue of non-qualified pension plan costs. MERC will be required to clearly identify all non-qualified pension plan costs included in its filing and clearly show that all have been removed from the revenue requirement with the exception of the amount associated with the amortization of the regulatory asset created in Docket No. 06-1287.

IX. Incentive Compensation Refund Mechanism

A. Introduction

Incentive compensation, when built into base rates, is paid by ratepayers even if performance goals are not met and no compensation is paid. MERC does not have a refund mechanism in place if it does not pay the incentive amounts reflected in base rates. The parties to this proceeding did not agree on the appropriate mechanism for returning unpaid incentive compensation to ratepayers in the future.

The Commission must determine whether a refund mechanism for unpaid incentive compensation is appropriate in this rate case, and if so, what mechanism must the Company implement.

B. Positions of the Parties

1. MERC

MERC did not oppose refunding incentive compensation that is not paid to employees. MERC disagreed with the Department's mechanism for the refund. Instead, MERC proposed an incentive tracker that would include carrying costs at MERC's prevailing short-term debt rate approved in this case for potential credit against the revenue requirement in the next rate case. MERC argued that customers would benefit from using the tracker rather than a refund because it would allow for some variation in the amount of compensation that is paid each year.

2. The Department

The Department recommended that the Commission establish a refund mechanism that returns unpaid incentive compensation to ratepayers rather than providing a windfall to shareholders.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that MERC did not demonstrate by a preponderance of the evidence that its proposed incentive tracker was reasonable and that MERC had not explained why it should be treated differently from other utilities in Minnesota on this issue.[43] The ALJ found that MERC's proposed tracker was unreasonable and that the Department's refund proposal for incentive compensation should be adopted by the Commission.[44]

D. Commission Action

The Commission has generally allowed recovery of incentive compensation. At the same time, the Commission recognizes that, by its very nature, incentive compensation may not be paid out to employees. An alternative to disallowing incentive payments is to require the utility to refund unpaid incentive compensation amounts to customers. The Commission will adopt the Department's refund proposal.

The Commission will require MERC to refund any incentive compensation costs included in the test year revenue requirement that are not paid out in a particular year. MERC may track the annual amounts to be refunded and make the refunds only after they reach $1 per customer.

In its thirty-day rate case compliance filing, MERC will be required to provide an explanation to the Commission of how the $1 per customer refund threshold would be implemented in the refund mechanism. MERC's compliance filing must explain whether the $1 per customer threshold means "whenever the cumulative amount exceeds an average of $1 per customer" or whether it has some other meaning and how the calculation would be made. MERC must also clarify that all annual incentive compensation costs included in the test year revenue requirement that are not paid out in a particular year (with no netting with years in which more than the test year level of incentive is paid) are to be tracked.

MERC will also be required to make an annual compliance filing within sixty days after the incentive compensation awards are or would have been paid. MERC must include in its compliance filing sufficient information to determine whether a refund is required and, if so, the amount of the refund. MERC must use a per dekatherm refund mechanism with any such refund.

X. Ratepayer-Supplied Funds

A. Introduction

The OAG recommended a rate base adjustment for ratepayer-supplied funds. The OAG stated that MERC funds its obligations for pensions and post-employment benefits at a different level than the expense level included for recovery of rates. The OAG proposed that the cumulative difference between funding and expense from 2007 through the projected 2011 test-year is $74,159, and that

[43] ALJ Report, ¶ 175.

[44] *Id.*

MERC's rate base for pensions and post-employment benefits should be reduced by that amount. The Department did not make a recommendation on this issue.

The Commission must determine the correct adjustment to rate base for ratepayer-supplied funds.

B. Positions of the Parties

1. MERC

According to MERC's calculations using the OAG proposal, the correct adjustment is $71,159. MERC agreed to adjust the rate base for ratepayer-supplied funds in the amount of $71,159.

2. OAG

The OAG argued that the correct adjustment to rate base should be a reduction of $74,159.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that the evidence demonstrated that for ratepayer-supplied funds MERC reduced the rate base by $71,159, and that amount accurately reflects the difference between funding expenses for its employee benefit obligations. The ALJ further concluded that no further adjustment is necessary.[45]

D. Commission Action

The Commission concurs with the ALJ on this issue and will reduce the rate base by $71,159 finding that this amount accurately reflects the difference between funding and expenses for MERC's employee benefit obligations.

XI. Non-Fuel O&M Expense Methodology

A. Introduction

MERC's method of projecting 2011 test year non-fuel O&M expenses was initially disputed by both the Department and the OAG. The issues between MERC and the Department were later resolved. The dispute between MERC and the OAG was not resolved.

The issue in this rate case is whether MERC's revised proposal for test-year non-fuel O&M expenses is reasonable.

B. Positions of the Parties

1. MERC

MERC initially calculated its 2011 test year non-fuel O&M by first applying 2010 inflation rates and 2010 known and measurable adjustments to actual 2009 non-fuel O&M expenses to determine

[45] ALJ Report, ¶ 179.

projected 2010 non-fuel O&M expenses. The Department requested that MERC update its calculations to use actual 2010 expenses to recalculate its proposed test year non-fuel O&M expenses based on 2010 actual expenses rather than 2010 forecasted non-fuel O&M expenses. MERC provided updated calculations as requested.

2. OAG

The OAG proposed a 6% cost reduction adjustment to non-fuel O&M expenses for the test year. MERC opposed the OAG proposal claiming that it was addressed in MERC's adjustment as requested by the Department and that imposing the 6% reduction would "double-count" the adjustment that MERC already agreed to. The OAG stated that by only correcting one year of the two-year period for inflation the result would not be a reasonable level of costs.

C. Recommendation of the Administrative Law Judge

Based on a proposal by the Department, the ALJ found that MERC agreed to a change in methodology adjusting its test year.[46] The ALJ further found that the result of this change in methodology resulted in a decrease in test year non-fuel O&M expenses of $2,215,136.[47] The OAG proposed an additional 6% reduction that was rejected by the ALJ. The ALJ concluded that the OAG's recommended additional 6% reduction was not necessary because the record reflects that the OAG's recommended correction to MERC's initially filed test year non-fuel O&M expenses had already been made, and that an additional reduction would not accurately reflect MERC's test year.[48]

D. Commission Action

The Commission adopts the Department's recommended non-fuel O&M expense reduction of $2,215,136, agreed to by MERC, and adopts the ALJ's finding that the additional 6% reduction to MERC's revised test year non-fuel O&M expenses recommended by the OAG would not accurately reflect MERC's test year costs.

XII. Construction Work in Progress (CWIP)

A. Introduction

Construction work not yet completed but in progress is shown as Construction Work In Progress (CWIP) on a utility's balance sheet. The Commission has the discretion to allow CWIP, and the associated Allowance for Funds Used During Construction (AFUDC) offset, in the calculation of test year costs where appropriate.

The issue in this rate case is whether MERC should be allowed to include CWIP in its rate base, and if so, should MERC be required to include the AFUDC offset on its income statement.

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[46] ALJ Report, ¶ 181.

[47] ALJ Report, ¶ 182.

[48] ALJ Report, ¶ 186.

B. Positions of the Parties

1. MERC

MERC did not initially include any amount for CWIP in its initial filing. In its rebuttal testimony, MERC recommended that its rate base should include $914,193 for CWIP in this proceeding. MERC argued that an AFUDC offset should not be required on the income statement. MERC has not historically calculated AFUDC absent a specific project. MERC stated that an offset for AFUDC is not appropriate for the short-term projects included in MERC's CWIP balance. In the event the Commission approved MERC's request for CWIP along with an AFUDC offset, MERC stated that it would calculate the AFUDC offset using the FERC AFUDC accounting methodology.

2. The Department

In its briefs, the Department agreed with MERC that CWIP should be included in the Company's rate base. The Department also agreed with the OAG in its briefs that MERC should be required to calculate an AFUDC offset.

At oral argument, the Department stated that the cleanest option would be for the Commission to deny the inclusion of CWIP in this proceeding.

3. OAG

In its briefs, the OAG initially opposed allowing CWIP in MERC's rate base. The OAG stated that if CWIP was allowed, then an AFUDC offset must be calculated. The OAG stated that the result of recognizing CWIP and AFUDC would produce approximately the same revenue requirement impact. The OAG and the Department concurred that it is normal accounting practice to include AFUDC in the income statement if CWIP is included in the rate base.

At oral argument, the OAG recommended that the Commission deny MERC's request to include CWIP in rate base.

C. Recommendation of the Administrative Law Judge

The ALJ found that it is not appropriate to increase CWIP by $914,193 unless a reasonable offset for AFUDC is included in the income statement.[49] The ALJ concluded that if the Commission approves the CWIP adjustment, MERC should propose an AFUDC amount in its compliance filing. If MERC is unwilling or unable to propose an AFUDC amount, the Commission should reject the requested increase to CWIP.[50]

D. Commission Action

Under Minn. Stat. § 216B.16, subd. 6, the Commission has discretion to allow or disallow CWIP in the rate base. Likewise, the Commission has the discretion to determine whether or to what extent

[49] ALJ Report, ¶ 192.

[50] *Id.*

the income used in determining the actual return will include an AFUDC offset under Minn. Stat. § 216B.16, subd. 6a. Importantly, the Commission is bound by Minn. Stat. § 216B.03 requiring that any doubt as to the reasonableness of a claimed cost is resolved to the benefit of the ratepayer.

At the Commission meeting on deliberation of this case, the Department and the OAG recommended that MERC's proposed CWIP adjustment to rate base be denied. The Commission agrees with the Department and the OAG on this issue and will not adopt the ALJ's recommendation. MERC has the burden of proof on this issue and has not demonstrated by a preponderance of the evidence that CWIP costs should be included in base rates.

The record on this issue has not been fully developed and the parties have not had a full opportunity to obtain adequate information since the request for CWIP was first presented in MERC's rebuttal testimony. MERC's CWIP balance includes short-term projects with no project-by-project documentation. On this record, the Commission cannot determine the reasonableness of MERC's request.

As a matter of clear and consistent regulatory practice, the Commission will deny MERC's request to include $914,193 in rate base in this proceeding.

XIII. Property Tax Expense

A. Introduction

In MERC's initial filing of this rate proceeding, MERC estimated its property tax expense for the 2011 test year to be $4,617,000. MERC received final assessment notices in December 2010 indicating that its 2010 property tax obligation would be $5,618,227, or $1,001,227 higher than the 2011 test year.

The issue is whether MERC should be allowed to update the property tax expenses included in its originally filed revenue requirement to reflect actual 2010 property tax obligations.

B. Positions of the Parties

1. MERC

MERC requested an increase in its 2011 property tax obligation to account for the increase in actual property tax assessments for 2010. MERC provided actual tax assessments issued by the State of Minnesota, Department of Revenue, in August 2011 showing that MERC should expect an increase in assessed property value of 4.1%. MERC stated that MERC's Minnesota personal property value assessments for all counties increased 27.8% from 2009 to 2010, and 7.8% from 2010 to 2011.

2. The Department

The Department agreed that MERC should be allowed to increase its 2011 property tax obligation to reflect the increase in actual property tax assessments for 2010.

3. OAG

The OAG opposed MERC's request and recommended that MERC's property tax expenses should be increased only by 10%, or $462,000. The OAG argued that MERC had not provided support to show that the level of property tax in Minnesota would continue at the 2011 levels. The OAG stated that property valuation and tax information for property owned by MERC in Washington County showed a decline in valuation from 2010 to 2011. The OAG proposed that, based on historical valuation fluctuations and the reduced valuation for 2012, a 10% increase was more appropriate than MERC's recommended increase.

C. Recommendation of the Administrative Law Judge

The ALJ found that MERC's Minnesota personal property value assessments for all counties was $112,625,033 in 2009, increasing to $144,618,203, or 27.8% in 2010, and increasing to $155,921,183, or 7.8% in 2011.[51] The ALJ concluded that, based on the actual assessed value of MERC's property, it was likely that MERC will actually experience an increase in Minnesota property tax obligations greater than the $1,116,578 request in the supplemental direct testimony.[52] Therefore, the ALJ recommended that the 2011 revenue requirement be increased by $1,116,578 to account for MERC's increased property tax obligation and that the Commission should take administrative notice of any decisions on MERC's property tax appeals made before the final order in this proceeding.[53]

D. Commission Action

The Commission concurs with the ALJ on this issue and will find that MERC has demonstrated by a preponderance of the evidence that its property tax obligations going forward are likely to be equal to or exceed MERC's 2011 test year revenue requirement of $5,733,578. The Commission takes administrative notice of any decisions on MERC's property tax appeals made before the final Order in this proceeding.

XIV. PGA Consolidation Phase-in Period

A. Introduction

MERC has proposed to consolidate its four purchased gas adjustment (PGA) systems into two. A purchased gas adjustment system permits a gas utility to adjust how much it recovers from ratepayers for the cost of gas, to reflect its cost to obtain it. Consolidating the systems will more closely reflect MERC's operations and will eliminate an unnecessary distinction between some similarly situated MERC customers. MERC proposes to implement one PGA system for customers served off pipelines that deliver gas from Canada, and another for customers served off the Northern Natural Gas pipeline.

[51] ALJ Report, ¶ 199.

[52] ALJ Report, ¶ 202.

[53] ALJ Report, ¶ 204.

B. Positions of the Parties

Whether it is appropriate to consolidate MERC's PGAs is uncontested. MERC and the Department agree that consolidation of MERC's purchased gas adjustment systems is reasonable. At issue is whether the consolidation plan should be phased in over a period of years.

The Department contends that the consolidation will result in price changes that would be significant to the average customer. It argues that "rate shock" would be mitigated by phasing in the changes over a three-year period. The Department recommends that the Commission adopt a three-year phase-in.

MERC asserts that a phase-in is unnecessary, and would be administratively difficult to implement. It argues that rate increases that may result from the consolidation are no more significant than monthly purchased gas adjustments that the Commission has previously approved. MERC recommends that the consolidation become effective on July 1 after final rates go into effect.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that MERC had not met its burden to establish by a preponderance of the evidence that immediate consolidation is reasonable. The ALJ recommended that the consolidation be phased in over three years.

D. Commission Action

The Commission will approve MERC's request to consolidate its four gas-cost recovery and PGA systems currently in place into two new PGAs: the MERC-NNG PGA system and the MERC-Consolidated PGA system. The consolidation proposal reasonably results in a system that more directly matches MERC's operations, and reduces MERC's costs of administering its PGA systems.

The Commission will also approve MERC's request that consolidated PGA rates be effective on July 1 after final rates go into effect, and that consolidation of the true-up factors be effective with the first Annual Automatic Adjustment and True-Up filings made on September 1 after final rates go into effect. The Commission is satisfied that in this case there is no need for a phased-in implementation.

Currently, the commodity price of natural gas is at a relative low, making this an opportune time to implement an administrative adjustment of this nature. The administrative complexity of a three-year, phased-in implementation is not warranted in this case.

XV. Uncollected CCRC revenues

A. Introduction

Minnesota utilities have a statutory obligation to spend and invest a portion of their revenues on projects that result in energy efficiency or energy conservation.[54] Utilities are also required to file conservation improvement plans (CIP). Expenses incurred for energy conservation improvements

[54] Minn. Stat. § 216B.241.

are considered in the rate making process "as if the investments and expenses were directly made or incurred by the utility in furnishing utility service."[55] However, certain large customers may be exempted from the general requirement to pay for conservation improvement expenses.[56] In a rate case, a Conservation Cost Recovery Charge (CCRC) is calculated, which is to be billed to non-exempt customers.

In the course of developing the record in this case, MERC discovered that since 2003, three of its customers who were not exempt from paying CIP costs were billed as though they were exempt. MERC acquired the customers on July 1, 2006 when it acquired Aquila. MERC has since continued treating the three customers as CIP exempt. Because the customers were incorrectly considered exempt by MERC, the CCRC was miscalculated in the previous rate case, and CIP costs have been under-recovered.

At issue is the proper remedy for the mistake.

B. Positions of the Parties

It is undisputed among the parties that MERC did not collect CCRC revenue from the three customers it identified, and that the CCRC was miscalculated in the previous rate case. MERC and the Department disagree about the nature and scope of an appropriate remedy.

MERC and the Department agree that although MERC did not collect CCRC revenues from the three customers, MERC did correctly credit its CIP tracker account for CCRC amounts attributable to one of the customers. The Department contends that MERC should credit its NMU CIP tracker an additional $862,089 for the remaining two customers, an amount reflective of the uncollected amounts from May, 2005 (the date of the earliest usage records available to MERC) through February 2011. The Department recommends that MERC not be required to pay a carrying charge on the uncollected amount in recognition of the Company's action to bring this matter forward.

MERC contends that it should only be required to credit its CIP tracker for uncollected amounts going back to January 1, 2010 (the date final rates went into effect in its prior rate case). MERC asserts it should not be held accountable for the mistake of its predecessor entity, because MERC merely continued the billing practices in effect when it took over operations for Aquila. MERC calculates the amount it recommends to be credited to be $448,526.

MERC alternatively recommends that the Commission apply by analogy the "billing error rule," and limit any required corrective action to a three-year look-back from the date MERC discovered the error. Under this recommendation, MERC would credit its CIP tracker for uncollected amounts going back to March 2007.

The OAG recommended that the Commission take notice that MERC's CIP tracker balance is incorrect and that the Commission act to correct it.

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[55] Minn. Stat. § 216B.16. subd. 6b.

[56] Minn. Stat. § 216B.241, subd. 1a.

C. The Recommendation of the Administrative Law Judge

The ALJ found that

> MERC has not established by a preponderance of the evidence that it is reasonable to collect from all non-exempt customers the amount that the Company and Aquila failed to properly collect from two [Super Large Volume] customers. Such a result is not consistent with the requirement in Minn. Stat § 216B.03 that requires the Commission to resolve all doubts as to reasonableness in favor of the consumer.[57]

D. Commission Action

Having considered the parties' arguments and the ALJ's recommendation, the Commission will modify the ALJ's recommendation to require MERC to credit its NMU CIP tracker with a revenue amount to be calculated by the Company, in consultation with the Department, representing uncollected amounts from July 2006, through February 2011, plus the additional revenue amount from March 2011 to the date final rates become effective in this docket.

In doing so, the Commission adopts the ALJ's finding that MERC has not established it is reasonable to fail to collect CIP charges from some of its non-exempt customers and to compensate by collecting those amounts from MERC's other non-exempt customers. Requiring MERC to credit its CIP tracker for uncollected amounts is an appropriate remedy.

By requiring a credit for the uncollected amounts going back to July 2006, the Commission is requiring MERC to account for uncollected amounts going back to the date MERC acquired Aquila's assets. On that date, MERC had the obligation to identify and correct the billing error. Accordingly, it serves as an appropriate and equitable look-back date for establishing MERC's responsibility to address the under-collection in its CIP account.

The Commission agrees with the Department's recommendation that MERC need not include a carrying charge in its CIP tracker credit.

XVI. Work Asset Management and PeopleSoft Expense

A. Introduction

Among the expenses in its initial petition, MERC included $1,357,410 in increased carrying costs and depreciation expenses related to its Work Asset Management implementation and for an upgrade to is PeopleSoft application. A Work Asset Management system is a collection of computer software applications that facilitate the management of utility assets and the activities to construct, maintain, and regulate those assets. PeopleSoft is an accounting and supply-chain management software package.

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[57] ALJ's Report, Finding 270.

B. Positions of the Parties

The OAG argued that MERC's software expenses should be limited to the amount recorded in 2010, $993,329. It contended that the 2010 expense reflected the costs of the software upgrades. MERC disagreed, asserting that only a portion of the annual costs of the upgrade were recorded in 2010.

C. The Recommendation of the Administrative Law Judge

The ALJ found that the 2010 expenses did not reflect a full year of software-related expenses, and recommended that MERC's test year include the full $1,357,410 of 2011 expenses that were attributable to the software upgrades.

D. Commission Action

Because MERC only recorded seven months of expenses in 2010, the OAG's recommendation would understate MERC's test year expenses by $364,081. The Commission therefore accepts and adopts the ALJ's recommendation that the test year include $1,357,410 in expenses attributable to the software upgrade and will allow the unamortized balance to be included in MERC's rate base calculation.

XVII. Bad Debt/Uncollectable Expense

A. Introduction

MERC initially forecasted $2,820,465 of test year uncollectable account expenses, sometimes called "bad debt" expenses. In response to a Department suggestion, MERC adjusted the bad debt expense amount to $1,134,941. Bad debt expenses can vary widely from year to year, but the Department expressed concern that neither the $2,820,465 nor the $1,134,941 forecasts were appropriate.

MERC accepted the Department's recommendation to set the test year bad debt expense to an amount equal to MERC's historical average of 0.776545% of its test year sales revenues. At issue is whether the revenue amount used in the calculation should include an estimate of the test year revenue deficiency.

B. Positions of the Parties

MERC, the OAG, and the Department all agreed that bad debt expenses can vary significantly from year to year, and agreed that calculating a level bad debt expense based on MERC's historical average was a reasonable approach. MERC and the Department also agreed that the bad debt calculation should include a revenue deficiency estimate of $11,907,362.

The OAG argued that the calculation should not include the revenue deficiency, in part because of the variability of bad debt expense from year to year, arguing that to do so would imbue the calculation with a false sense of accuracy.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that the bad debt expense be calculated based on MERC's historical average bad debt expense as a proportion of total revenues, and by including the Department's initial revenue deficiency $11,907,362, finding that doing so would represent the most reasonable and accurate cost measurement tool of those under consideration.

D. Commission Action

The Commission accepts and adopts the ALJ's recommendation concerning the inclusion of $11,907,362 to represent the test year revenue deficiency in order to calculate MERC's test year bad debt expense.

Bad debt expenses can vary significantly from year to year. Additionally, MERC's forecasts for bad debt expense during the test year caused the parties enough concern for being either too high or too low that they agreed instead to calculate the expense using a historical average. Under these circumstances, it is reasonable to calculate MERC's test year bad debt expense using a historical average rather than rely on forecasted amounts.

The Commission agrees with the ALJ's reasoning that including the revenue deficiency in the bad debt calculation is appropriate. MERC's test year revenues will include the revenue deficiency decided in this case. Including the revenue deficiency amount matches test year revenues and expenses, and yields the most accurate revenue amount to include in the bad-debt-expense calculation. The Department's initial test year revenue deficiency amount is a reasonable proxy for purposes of performing the calculation. The Commission therefore approves the ALJ recommendation to calculate the bad debt expense by applying the bad debt expense factor of 0.776545% to the test year revenue level, including the Department's original test year revenue deficiency, to determine the revenue requirement.

XVIII. Regulatory Asset – Cloquet Plant Amortization

A. Introduction

MERC proposed to include in its rate base $9,364,574 of regulatory assets. Regulatory assets are an accounting category for ratepayer obligations that a regulatory entity such as the Commission authorizes a utility to defer for ratemaking purposes. In Docket No. G-007, 011/M-06-1287, the Commission approved MERC's proposal to include $8,934,972 in regulatory assets related to MERC's acquisition of Aquila. MERC agreed to reduce the amount it seeks to include in its rate base by $392,860, upon the request of the OAG. However, MERC did not agree to the full amount of the reduction recommended by the OAG.

B. Positions of the Parties

At the time of the proceedings before the ALJ, the OAG argued that MERC's regulatory asset amount should be limited to the amount previously authorized by the Commission. It contended that regulatory assets require prior approval, and that $436,358 MERC sought to recover was in addition to that which had been previously approved, and should be excluded.

Although MERC reduced its regulatory asset amount by $392,860, MERC disagreed with the OAG's characterization of one regulatory expense: $43,498 attributable to amortization of its Cloquet plant. MERC contended that the Cloquet plant amortization has been previously included in MERC's rate base, and therefore was properly included as a regulatory asset.

C. The Recommendation of the Administrative Law Judge

The ALJ found that the rate base should include the $43,498 that represents the Cloquet plant amortization, labor actuals, and labor loader that were included in the rate base in MERC's last rate case. The OAG did not raise an exception to this finding.

D. Commission Action

The Commission accepts and adopts the ALJ's findings on this issue. MERC's rate base should include the $43,498 that represents the Cloquet plant amortization, labor actuals, and labor loader that were included in the rate base in MERC's last rate case in Docket No. G-007, 011/GR-08-835.

XIX. Employee Compensation

A. Introduction

Total employee compensation includes several distinct employee-related expenses, including salary, health and dental benefits, and pension and other retirement plan expenses. In addition to expressing concern about the details of certain specific employee compensation expenses, the OAG specifically challenged the magnitude of the increase in total compensation since MERC's last rate case. At issue is whether the overall increase in employee compensation, irrespective of the necessity and prudence of the individual components, warrants excluding some of MERC's compensation expense from rate recovery.

B. Positions of the Parties

The OAG contends that MERC's overall employee compensation expense is too large. To support its argument, the OAG calculated MERC's total compensation expenses for the 2008 test year in the prior rate case, and for the 2011 test year, and concluded that total compensation expenses increased 34% over the period. The OAG contrasts that percentage increase with "the 1 to 2 % annual compensation increases in total compensation received by typical U.S. workers." It contends that MERC's allowed compensation expense should be limited to an increase comparable to that experienced by typical U.S. workers over the same period.

MERC disputes the usefulness of considering the total compensation expense, arguing that every component of the overall compensation expense has adequate support in the record. MERC also disputes that the amount of compensation expenses in the 2008 rate case is relevant to determine whether 2011 test year expenses should be allowed for rate recovery. Additionally, MERC contends that the OAG's calculation does not correctly reflect MERC's 2008 compensation costs, and claims that the true increase from 2008 to 2011 is 14%.

C. The Recommendation of the Administrative Law Judge

The ALJ made findings on specific disputed components of employee compensation, but did not make an express finding addressing the OAG's concern about the overall level of employee compensation.

D. Commission Action

The Commission declines to take any action based on MERC's overall test year compensation expenses. The compensation-expense increase from the prior rate case cannot be considered in a vacuum. Changes in total compensation amounts obscure fluctuations in individual components, each of which may be rising or falling independent of one another. While the OAG's efforts to compare the 2008 and 2011 total compensation expense amounts are informative, the traditional practice of scrutinizing specific compensation-expense categories for whether they are just and reasonable is more probative.

The parties have addressed several individual components of MERC's overall compensation expense in this case, including pension expenses, employee incentive costs, and employee benefits. If the aggregate result of MERC's compensation expenses is unreasonable, the contributing factor or factors can be identified with more granularity and specificity than as an unidentified component in a challenged sum. For example, according to the OAG's calculation, a major contributor to the challenged compensation expense increase in this case is the increase in MERC's pension contribution expense.

OAG's challenge to the size of the total compensation increase is therefore in part an indirect challenge to the propriety of MERC's pension expense, which is addressed directly in section VIII of this order. Additionally, the OAG's percentage increase calculation does not reflect per-employee or per-employee-hour costs, and it is not clear that using the total compensation increase of a typical U.S. worker as a comparison is appropriate.

For these reasons, having considered the OAG's arguments concerning MERC's overall test year compensation expenses, the Commission takes its compensation-related actions in the sections of this order that address specific components of compensation.

XX. Residential and Small Commercial and Industrial (C&I) Customer Charges

A. Introduction

The monthly customer charge is used to help recover fixed customer-related costs. MERC and the Department agreed to the increases in residential and small C&I customer charges.

B. Positions of the Parties

1. MERC

MERC initially recommended a $9.50 monthly residential customer charge, a 31% increase. MERC also recommended a $14.50 monthly increase for small C&I customers, a 21% increase. MERC argued that the increases are necessary to address MERC's higher weather risk, unstable cash flows,

and the need for accurate price signals. MERC stated that the increases are supported by MERC's Class Cost of Service Study.

2. The Department

The Department did not oppose increasing the residential and small C&I customer charges, but recommended a smaller increase for the residential class, to $8.50. The Department stated that the increase per month for these customers would appropriately assign costs to each class. The increase to the residential customers was appropriate and would avoid rate shock. MERC accepted the Department's recommendation.

3. OAG

The OAG recommended no increase in the monthly customer charges for residential and small C&I customers. The OAG argued that the Class Cost of Service Study has limitations and may not provide the best price signal to customers. The OAG argued that MERC has not provided any marginal cost support to justify resetting the customer charge.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve the agreement between MERC and the Department to increase the residential customer charge to $8.50 per month and the small C&I customer charge recommendation of $14.50 per month.[58]

D. Commission Action

The Commission recognizes MERC's need to appropriately assign costs to each customer class and concurs with the ALJ on this issue. The Commission adopts the ALJ's Finding 321 and finds that a higher customer charge will result in more level winter and summer bills, provide a more accurate price signal to customers by bringing their rates closer to the true cost of service, and provide incrementally more stable cash flow to the utility.

The Commission finds that MERC's proposal to increase the basic monthly residential and small C&I customer class charges is reasonable and will approve MERC's proposed residential customer charge of $8.50 per month and proposed small C&I customer charge of $14.50 per month.

XXI. Finding 52 Is Not Adopted

A. Introduction and Finding of the Administrative Law Judge

Among findings related to the Commission's responsibility to establish just and reasonable rates, the ALJ made the following finding:

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[58] ALJ Report, ¶ 329.

> Setting the rates at or near the embedded cost to serve each customer class serves the public interest in assuring that adequate price signals are sent to customers who receive service.[59]

The finding included a footnoted reference to Minnesota Statutes section 216B.03. For the reasons set forth below, the Commission does not adopt this finding.

B. Commission Action

The ALJ's finding is problematic. First, embedded costs do not necessarily send price signals to customers that reflect either current market costs or marginal costs of providing service. Embedded costs reflect the historical costs of developing a system.

But more saliently, when setting rates the Commission considers many factors in addition to the costs of providing service, such as economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; and the ability to bear, deflect, or otherwise compensate for additional costs. Consideration of factors besides cost-causation is consistent with the Commission's statutory responsibility to set just and reasonable rates.[60] The ALJ's finding oversimplifies the Commission's rate-setting mandate. Accordingly, the Commission does not adopt Finding 52.

XXII. Overall Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a total Minnesota jurisdictional gross revenue deficiency for the 2011 test year of $11,047,296, as shown.

[59] ALJ's Report, Finding 52.

[60] *See* Minn. Stat. § 216B.03

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2011

Description	MERC - MN
Average Rate Base	$ 189,808,628
Rate of Return	7.8275%
Required Operating Income	$ 14,857,270
Operating Income	$ 8,374,115
Income Deficiency	$ 6,483,155
Gross Revenue Conversion Factor	1.7040
Gross Revenue Deficiency	$ 11,047,296

B. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional rate base for the 2011 test year is $189,808,628, as shown below.

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2011

Description	MERC-MN
PLANT IN SERVICE	
Production and Storage	$ 1,411,188
Transmission	$ 7,004,639
Distribution	$327,053,294
Total Plant In Service	$335,469,121
RESERVE FOR DEPRECIATION	
Production and Storage	$ 447,732
Transmission	$ 2,923,088
Distribution	$147,599,538
Total Reserve For Depreciation	$150,970,358
NET PLANT IN SERVICE	
Production and Storage	$ 963,456
Transmission	$ 4,081,551
Distribution	$179,453,756
Total Net Plant In Service	$184,498,763
Construction Work in Progress	$ -
LESS: Customer Advances	$ 130,480
LESS: Accumulated Deferred Income Taxes	$ 13,172,098
Working Capital:	
Cash Working Capital	$ (1,984,067)
Materials and Supplies	$ (1,217,291)
Gas Storage Inventory	$ 12,842,087
Regulatory Assets/Liabilities	$ 8,971,714
Total Working Capital	$ 18,612,443
TOTAL AVERAGE RATE BASE	$189,808,628

C. Operating Income Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the 2011 test year under present rates is $8,374,115, as shown below.

Operating Income Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2011

Description	MERC-MN
UTILITY OPERATING REVENUES	
Retail Revenue	$ 263,405,946
Late Payment Revenue	$ 1,005,000
Other Operating Revenue	$ 314,700
Total Operating Revenues	$ 264,725,646
UTILITY EXPENSES	
Purchased Cost of Gas	$ 185,725,253
Other Production	$ 17,288
Gas Supply	$ 735,883
Transmission	$ 52,851
Distribution	$ 13,495,501
Customer Accounting	$ 11,350,358
Customer Service & Information	$ 792,674
Administrative & General	$ 16,249,165
Total Operating Expenses	$ 228,418,973
Amortizations	$ 8,856,622
Depreciation	$ 10,164,714
Taxes Other than Income Taxes	$ 6,952,636
Total Depreciation & Other Taxes	$ 25,973,972
Federal Income Tax	$ 1,489,803
State Income Tax	$ 337,225
Interest Synch	$ 131,558
Total Income Taxes	$ 1,958,586
Total Expenses	$ 256,351,531
Net Income	$ 8,374,115

XXIII. Implementation and Compliance

The Commission will require the Company to make compliance filings 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 any 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.

The Commission will so order.

ORDER

1. The Commission finds that the record demonstrates that Minnesota Energy Resources Corporation is entitled to increase its total gross annual Minnesota jurisdictional revenues by $11,047,296 to produce total gross annual jurisdictional operating revenues of $275,772,942.

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

3. The Commission finds that the appropriate sales forecast for this rate case is the Company's initial sales forecast, corrected only as needed to resolve any errors favoring ratepayers discovered in the course of the audit discussed in the text above. The Commission makes the following clarifications to Findings 141 and 454 in the Report of the Administrative Law Judge:

   141. The Administrative Law Judge concludes that MERC's initial sales forecast, adjusted if needed to resolve any errors stemming from the audit in favor of ratepayers, is reasonable and recommends that the Commission use MERC's initial sales Page 2 of 23 forecast, adjusted if needed, for setting rates in this proceeding, noting that it will result in a revenue requirement nearly $1.9 million lower than MERC's revised sales forecast.

   454. MERC has agreed to, and is currently in the process of conducting a full billing system audit. The data existing after this full audit can be used to calculate MERC's RDM, ~~whether the Commission approves~~ based on any corrections from this audit to MERC's original forecast or the later one.

4. The Commission specifically accepts, adopts, and incorporates Findings 134, 135, and 140 in the Report of the Administrative Law Judge, set forth below:

   A. Paragraph 134 – MERC has agreed to conduct a complete audit of its billing system, as proposed by the Department and the OAG. MERC, the Department, and the OAG have agreed that the parties will reach mutual agreement on the use of an external auditor and the scope of the audit on MERC's billing systems. MERC has agreed that if the audit identifies any understatement of the sales and customer counts, the record should be reopened to make any necessary modifications to the final rates in this proceeding.

B. Paragraph 135 – If significant issues with MERC's data are uncovered during the audit that would result in lower rates for MERC's ratepayers, the Department recommends that the Commission reserve the right to revisit the rates set in this proceeding.

C. Paragraph 140 – Since MERC has agreed to the proposed billing audit, including the rate revision provision, the data issues identified by the Department and the OAG have been addressed.

5. The Company shall update its cash working capital to reflect the decisions made in this Order.

6. The Commission approves MERC's request to consolidate its Purchased Gas Adjustment rates, with rate consolidation effective on the July 1 following the effective date of final rates and true-up factor consolidation effective with the first Annual Adjustment and True-Up filings made on the September 1 following the effective date of final rates.

7. The Commission adopts the recommendation of the Administrative Law Judge and approves the continuation of the farm tap inspection program, clarifying as follows.

   A. The Company shall continue to send farm-tap safety and information brochures to new farm tap customers before they take service and to all existing farm customers annually.

   B. The Company shall continue to file annual reports on its farm tap inspection program on or before April 1 of each year.

   C. Within 90 days of the end of each five-year inspection cycle and in each general rate case, the Company shall file with the Commission, the Department, and the Minnesota Office of Pipeline Safety a five-year report including cumulative results of the inspection program and any recommendations for future improvements.

8. The Company shall track rate case expense recoveries exceeding the authorized test-year expense, for possible crediting against the revenue requirement in the next rate case.

9. MERC shall refund any incentive compensation costs included in the test year revenue requirement that are not paid out in a particular year. MERC may track the annual amounts to be refunded and make the refunds only after they reach $1 per customer.

   A. In its thirty-day rate case compliance filing, MERC shall provide an explanation to the Commission of how the $1 per customer refund threshold would be implemented in the refund mechanism. MERC's compliance filing must explain whether the $1 per customer threshold means "whenever the cumulative amount exceeds an average of $1 per customer" or whether it has some other meaning and how the calculation would be made. MERC must also clarify that all annual incentive compensation costs included in the test year revenue requirement that are not paid out in a particular year (with no netting with years in which more than the test year level of incentive is paid) are to be applied to the tracker account.

B. MERC shall make an annual compliance filing within sixty days after the incentive compensation awards are or would have been paid.

C. MERC shall include in its compliance filing sufficient information to determine whether a refund is required and, if so, the amount of the refund.

D. MERC shall use a per dekatherm refund mechanism with any such refund.

10. The Company shall clearly identify all non-qualified pension plan costs included in its filing and clearly show that all have been removed from the revenue requirement with the exception of the amount associated with the amortization of the regulatory asset created in Docket No. 06-1287.

11. MERC's request for a full revenue decoupling pilot program in the form recommended by the Administrative Law Judge is approved with the following modifications or conditions.

A. MERC shall file annual reports to the Commission that specify the Revenue Decoupling Mechanism (RDM) adjustment to be applied to each rate class for the billing period and demonstrate annual progress toward achieving the 1.5% energy efficiency goal set forth in Minn. Stat. § 216B.241.

B. MERC shall state in its RDM tariff that the Commission has the authority to modify or suspend the rates in this pilot program if warranted by unexpected circumstances.

C. MERC shall use the same billing determinants (customer counts, etc.) used to set final rates to determine the RDM baseline.

D. The appropriate sales forecast for setting final rates and for decoupling purposes (i.e., in the RDM) is MERC's initial sales forecast, corrected only as needed to resolve any errors discovered in the Vertex billing audit in favor of ratepayers. If no such errors are found, then MERC's initial sales forecast shall be used.

E. The decoupling pilot program may take effect with the implementation of new rates in this proceeding.

F. The decoupling program may remain in effect for no more than three years (i.e., thirty-six months), unless it is extended by Commission action.

G. In its thirty-day rate case compliance filing, MERC shall submit a proposal for implementing its RDM mechanism mid-year, including prorated RDM baseline calculations for the part of the year MERC expects the RDM to be in place at the beginning of the program and at the end of the program.

H. In its thirty-day rate case compliance filing, MERC shall submit revised revenue decoupling tariff language that incorporates all the Commission's decisions in this rate case.

I. MERC shall explain its revenue decoupling program in its notice to customers about final rates at the end of this case and in another notice when the first annual revenue decoupling rate adjustment is implemented on customer bills.

12. Within 30 days of the date of this order the Company shall make the following compliance filings:

A. Revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions herein, along with the proposed effective date, and including the following information:

B. Breakdown of Total Operating Revenues by type;

C. 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:

1. Total revenue by customer class;
2. Total number of customers, the customer charge and total customer charge revenue by customer class; and
3. For each customer class, the total number of commodity and demand related billing units, the per unit commodity and demand cost of gas, the non-gas unit margin, and the total commodity and demand related sales revenues.

D. Revised tariff sheets incorporating authorized rate design decisions;

E. Proposed customer notices explaining the final rates, the monthly basic service charge, rate area consolidation, and, if approved, the revenue decoupling pilot program.

F. A revised base cost of gas and supporting schedules incorporating any changes made as a result of this rate case, and automatic adjustments establishing the proper adjustments to be in effect at the time final rates are implemented.

G. If final authorized rates are lower than interim rates, a proposal to make refunds of interim rates, including interest calculated at the average prime rate, to affected customers.

H. A recalculation of the Conservation Cost Recovery Charge, using the Commission-approved test year CIP expense and the Commission-approved test year sales volumes less the appropriate CIP exempt volumes, but including the three non-exempt CIP customers' volumes erroneously excluded by MERC in its original petition.

I. A demonstration that the CIP tracker account has been properly credited with the appropriate Conservation Cost Recovery Charge amounts during the interim rate period or an explanation of how the Company plans to ensure that the tracker account is properly credited after final rates have been determined.

13. Comments on compliance filings are due 30 days from the date they are filed. Comments on the Company's proposed customer notice are not necessary.

14. In its next rate case, the Company shall fully support the reasonableness of having ratepayers pay 100% of its pension obligation.

15. In its next rate case, the Company shall continue reporting, in the same manner as in this case, winter construction charges, abnormal construction charges, and charges for disconnection and reconnection in cases of tampering.

16. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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