BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John A. Tuma	Commissioner
Betsy Wergin	Commissioner

In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota

ISSUE DATE: June 8, 2015

DOCKET NO. E-111/GR-14-482

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

PROCEDURAL HISTORY

I. Initial Filings and Orders

On July 2, 2014, Dakota Electric Association (Dakota Electric or the Cooperative) filed this general rate case. The Cooperative asked to increase Minnesota retail electric rates by some $4,189,000, or 2.1% per year. The filing included a proposed interim rate schedule.

On August 29, 2014, the Commission issued three orders in this case:

- an order accepting the filing and suspending the proposed final rates;
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested-case proceedings; and
- an order setting interim rates for the period during which the rate case was being resolved.

II. The Parties and Their Representatives

The following parties appeared in this case:

- Dakota Electric Association, represented by Harold LeVander, Jr., Felhaber, Larson, Fenlon & Vogt, P.A.
- Minnesota Department of Commerce (Department), represented by Linda S. Jensen and Peter E. Madsen, Assistant Attorneys General.
- Office of the Minnesota Attorney General–Residential Utilities and Antitrust Division (OAG), represented by Ian M. Dobson, Assistant Attorney General.

III. Proceedings before the Administrative Law Judge

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

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held evidentiary hearings in Saint Paul on December 18, 2014. After the hearings the parties filed initial briefs, reply briefs, and proposed findings of fact.

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

- Apple Valley Senior Center, Apple Valley—December 2
- Dakota Electric Association, Farmington—December 2

IV. Public Comments

The Administrative Law Judge held two public hearings. Representatives of the Cooperative, the Department, the Office of the Attorney General, and the Commission attended.

Four members of the public spoke at the public hearings. Among other things, the speakers asked questions about the Cooperative's cost-control efforts, especially in regard to labor and travel costs; questioned the Cooperative's decision to seek a higher percentage increase for residential customers than business customers; and sought clarification on the impact of raising the fixed customer charge as opposed to volumetric charges.

Seven members of the public filed written comments, all opposing the proposed rate increase.

V. Proceedings before the Commission

On March 2, 2015, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law and Recommendations (the ALJ's Report). The Cooperative and the OAG filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700.

On April 23, 2015, the Commission heard oral argument from the parties and the record closed under Minn. Stat. § 14.61, subd. 2.

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

FINDINGS AND CONCLUSIONS

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[1] The Minnesota Supreme Court has described the Commission's statutory mandate for determining

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

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.[2] 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.

Dakota Electric differs from an investor-owned utility in that, as a cooperative, its ratepayers are also its only investors.[3] Instead of balancing the interests of ratepayers and shareholders, then, the Commission must balance the interests of members as ratepayers and as contributors of patronage capital.

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.

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

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

[3] Dakota Electric is an electric cooperative organized under Minn. Stat. § 308.05. While cooperatives are generally exempt from rate regulation under Minn. Stat. § 216B.02, subd. 4, Dakota Electric has elected to be subject to rate regulation under Minn. Stat. § 216B.026.

> it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[4]

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

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

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

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[7]

VI. Summary of the Issues

In its *Notice and Order for Hearing*, the Commission asked the parties to address and provide schedules and supporting documentation showing the matching of power-cost revenue to power-cost expense in the pro forma test-year financial schedules. The Cooperative and the Department

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

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

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

worked together to provide this information, which the ALJ concluded met the requirements of the *Notice and Order*. The Commission concurs, but will require follow-up in the next rate case, directing the Cooperative to include in its initial filing its work papers for both the purchased-power revenue and purchased-power expense amounts in the pro forma test-year financial schedule.

The parties worked efficiently to narrow the other issues in the case. The Cooperative and the Department reached agreement on all issues; that agreement was memorialized in a settlement filed on January 5, 2015,[8] and amended on January 20 to reflect technical corrections.[9]

The OAG contested the settlement's resolution of six issues, listed below.

Financial Issues

- ***Travel and Miscellaneous Employee Expenses—***Has the Cooperative demonstrated the reasonableness and prudence of business expenses relating to employee and Board member travel, employee and Board member meals, and food and event expenses for its Board of Directors?

- ***Payroll Annualization Adjustment—***Has the Cooperative demonstrated the reasonableness of its proposed $690,427 upward adjustment to test-year payroll costs and related benefits?

- ***Reduction in Hours Billed to Subsidiary—***Has the Cooperative demonstrated the reasonableness and prudence of making no reduction to test-year payroll costs to reflect the reallocation of some 842 work hours per year from unregulated to regulated operations?

Class Cost of Service Study (CCOSS) Issues

- ***Minimum System Study—***Does the Cooperative's minimum-distribution-system study properly classify distribution costs as customer-related or capacity-related?

Rate Design Issues

- ***Class Revenue Apportionment—***What percentage of the revenue requirement should be allocated to each customer class?

- ***Residential, Farm, and Small-General-Service Customer Charges—***At what levels should the Commission set the fixed monthly charges for residential, farm, and small-general-service customers?

These issues are examined individually below.

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[8] Ex. 128 (Settlement Agreement).

[9] Ex. 128A (Amendment to Settlement Agreement).

VII. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held a formal evidentiary hearing and two public hearings. She reviewed the testimony of nine expert witnesses and related hearing exhibits. She heard testimony from all members of the public who appeared at the public hearings and read all written comments submitted by members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. She made 181 findings of fact and conclusions of law and made recommendations on all stipulated, settled, and contested issues based on those findings and conclusions.

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

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations.

FINANCIAL ISSUES

VIII. Travel and Miscellaneous Employee Expenses

A. Introduction

The Cooperative included in test-year expense some $800,000 for travel, lodging, meals, membership dues, hospitality, and similar expenses. Such expenses are subject to detailed filing requirements under Minn. Stat. § 216B.16, subd. 17, which prohibits the Commission from permitting rate recovery of "travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service."

The OAG challenged five of these expenses:

1) $2,066 in travel costs for a Board member to attend regional cooperative meetings while running for election to the Board of the National Rural Utilities Cooperative Finance Corporation (CFC), the Cooperative's primary long-term lender.

2) The $672 premium paid for last-minute airfare to send a Cooperative employee to a conference in Washington, D.C.

3) $3,909 for food served to Cooperative employees and Board members at work-related meetings and workshops throughout the year.

4) $522 for a "holiday luncheon" for Board members and select employees attending the December Board meeting.

5) $3,141 for a retirement party for the Cooperative's attorney.

Dakota Electric withdrew its request for recovery of the retirement-party expense, stating the expense was likely to be nonrecurring.

B. Positions of the Parties

1. The OAG

The OAG argued that the four remaining expense items were unnecessary, were imprudent, and had not been shown to provide direct benefits to ratepayers.

2. Dakota Electric

Dakota Electric argued that the four remaining expenses were prudent, were reasonable, and directly benefited ratepayers, as set forth below:

1) *Board member travel while running for CFC Board*—CFC is the Cooperative's primary long-term lender. Gaining representation on the CFC Board would enhance the Cooperative's understanding of CFC policies and permit the Cooperative to influence the future development of those policies, to the benefit of its ratepayers.

2) *Non-discounted airfare*—The Cooperative seldom pays full price for last-minute airfare, but this was an isolated instance in which it was necessary. No one challenged the appropriateness of sending an employee to the Washington, D.C. conference for which the airfare was purchased; last-minute travel arrangements had to be made in this unusual case.

3) *Food at employee and Board meetings*—Serving food at team meetings, all-employee meetings, and Board meetings is consistent with normal business practice and helps keep employees and Board members refreshed, alert, and productive during meetings.

4) *Holiday Board luncheon*—This luncheon was the normal lunch served at monthly Board meetings and was called a holiday luncheon because it was served at the December meeting. The meeting was attended by the same Board members and employees who normally attend monthly Board meetings. Serving lunch was appropriate for the reasons set forth in the preceding paragraph.

3. The Department

The Department concurred with the Cooperative; the settlement agreement it had negotiated with the Cooperative permitted rate recovery of the test-year expenses challenged by the OAG.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Cooperative had demonstrated that the four remaining expenses challenged by the OAG were reasonable, necessary, and benefitted ratepayers, for the reasons outlined by the Cooperative. She recommended permitting their recovery in rates.

D. Commission Action

The Commission concurs with the Administrative Law Judge that the four remaining expenses meet the statutory standard for rate recovery—they are reasonable and necessary for the provision of utility service.[10]

While the Public Utilities Act sets specific, detailed filing requirements for costs related to travel, lodging, meals, and Board members' expenses, it permits their recovery in rates unless the Commission deems them "unreasonable and unnecessary for the provision of utility service." The Commission concurs with the Cooperative and the ALJ that these expenses were reasonable and necessary for the reasons given by the Cooperative.

In short, it was reasonable and necessary to (a) nurture a close and productive relationship with its major long-term lender; (b) send an employee to an important Washington, D.C. conference despite the need to pay last-minute airfare prices; (c) incur reasonable expenses to serve food at Board meetings and work-related employee meetings, to ensure that attendees remain alert, refreshed, and productive.

IX. Payroll Annualization Adjustment

A. Introduction

The settlement agreement included in test-year payroll expense an annualization adjustment of $690,427 over actual 2013 payroll costs.[11] The stated purpose of the adjustment was to reflect the cost of a new position added after the 2013 test year and to correct for non-recurring salary savings in 2013 resulting from an abnormally high number of vacancies and an abnormally high number of extended vacancies.

B. Positions of the Parties

1. Dakota Electric

Dakota Electric argued that its actual payroll costs during the 2013 test year were abnormally low and that to avoid under-recovery, test-year costs must be adjusted to reflect the impact of known and measurable cost changes occurring in 2014 and continuing thereafter.

The Cooperative claimed two known and measurable changes: First, it had added an additional, full-time position (powerline design technician) to its 195-member workforce in 2014, and the cost of that position was not included in 2013 payroll costs. Second, its 2013 payroll costs had reflected both an aberrantly high number of vacancies (16) and an aberrantly high number of extended vacancies, including two involving terminal illnesses.

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[10] Minn. Stat. § 216B.16, subd. 17 (a).

[11] The ALJ's Report gave the amount of the annualization adjustment as $465,435 (see ALJ's Report at ¶ 63), but all parties agreed that the amount of the adjustment was actually $690,427, with benefits factored in. The Commission will amend the Report to so state, to avoid confusion.

The Cooperative argued that using actual 2013 payroll costs as test-year costs would be seriously off the mark, in that it would be equivalent to denying rate recovery for six full-time positions. It argued that vacancy levels and vacancy durations in 2013 were clearly aberrant, pointing out that vacant positions in 2013 were open nearly twice as long, in the aggregate, as vacant positions during the previous year.[12] The Cooperative argued that test-year payroll costs should be based on the assumption that all positions in its workforce were always filled.

At oral argument the Cooperative stated that, should the Commission decide not to base test-year payroll costs on the assumption that every position would always be filled, it should at least grant an annualization adjustment in the $354,745 to $404,745 range, reflecting (a) the $101,000 cost of the new position; (b) the $103,000 in non-recurring salary savings from the extended vacancies due to terminal illnesses; and (c) the $150,000 to $200,000 in non-recurring salary savings from the higher-than-average number of overall vacancies in 2013.

2. The Department

The Department had negotiated and signed the settlement agreement, which included the proposed $690,426 annualization adjustment; the Department concurred with the Cooperative.

At oral argument the Department stated that it believed Dakota Electric had met its burden of proof and had established known and measurable changes in test-year payroll costs totaling $690,427. The agency stated that incorporating known and measurable cost changes into test-year costs was standard ratemaking practice.

3. The OAG

The OAG challenged the Cooperative's claim that its actual 2013 payroll costs were demonstrably and aberrantly lower than its payroll costs were likely to be in 2014 and succeeding years.

The OAG pointed out that Dakota Electric's 2013 overall payroll costs were not lower than overall payroll costs in recent years and argued that it would be unreasonable to set rates based on the assumption that every position in the workforce would be filled at all times. The OAG argued that employee turnover is a given and that rates should be set assuming some level of unfilled positions.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the OAG's challenge had merit. She found that employee turnover was a basic fact of business life and did not rise to the level of a known and measurable change justifying an adjustment to test-year costs. She emphasized the importance of the test-year concept, which rests on the assumptions that actual costs will differ from test-year costs, that some differences will favor the utility and some will not, and that not adjusting for either type of difference maintains the integrity of test-year-based ratemaking.

The ALJ therefore recommended denying the request for an annualization adjustment to test-year payroll costs, with the exception of the portion of that adjustment related to the new powerline-design-technician position.

[12] Ex. 203, Schedule SL-4 (Lee Direct).

D. Commission Action

The Commission finds that the alternative position advanced by the Cooperative at oral argument represents the most reasonable resolution of this issue.

The Administrative Law Judge and the OAG are clearly correct that some level of employee turnover is normal and foreseeable, and that it may not be reasonable to set test-year payroll costs on the assumption that all workforce positions are filled 100% of the time.

At the same time, the Cooperative submitted undisputed testimony that test-year vacancies were significantly higher in number and longer in aggregate duration than typical-year vacancies. In fact, the record demonstrates that worker-days lost to vacancies during the 2013 test year were nearly double those lost in the previous year. And no one disputes that Dakota Electric added a new position after the test year closed and that the cost of that position is some $101,000 per year.

The Commission therefore finds that Dakota Electric has demonstrated on the record that 2013 test-year payroll costs are lower than ongoing payroll costs are likely to be, due to known and measurable changes associated with the probable return of normal levels of employee turnover and the addition of a new position.

The addition of the new powerline design-technician position is a classic known and measurable change—its existence, its permanence, and its associated costs have been thoroughly established on the record. The filled position should be reflected in test-year costs and the resulting rates.

Similarly, the record demonstrates that the number and duration of vacancies during the 2013 test year was abnormally high, that those vacancies have now been filled, and that employee turnover has returned to normal levels. This, too, is a known and measurable change that should be reflected in test-year costs and the resulting rates.

The Commission will therefore approve an annualization adjustment in the alternative amount of $354,745 recommended by the Cooperative. This amount reflects (a) the $101,183 cost of the new position; (b) the restoration of $103,562 in cost reductions from atypical extended vacancies resulting from terminal illnesses; and (c) the restoration of $150,000 in residual cost reductions associated with the unusually high number of overall vacancies in the 2013 test year.

This adjustment will ensure that test-year payroll costs reasonably approximate the Cooperative's payroll costs going forward, undistorted by the anomalies in the 2013 actual payroll costs.

X. Reduction in Hours Billed to Subsidiary

A. Introduction

In Dakota Electric's last rate case, filed in 2009, test-year costs and revenues showed 23 Cooperative employees billing 1,197 hours to an unregulated affiliate, Energy Alternatives, Inc. By the 2013 test year, these numbers had dropped to 13 employees billing 355 hours to the affiliate.

The OAG contended that employee-compensation amounts representing the 842-hour difference should be subtracted from test-year payroll costs.

B. Positions of the Parties

The OAG argued that eliminating 842 hours of work formerly devoted to serving the unregulated subsidiary translated into having 842 extra work-hours not needed or used to provide regulated utility service. The Cooperative put the financial impact of this change at $57,700.[13]

Dakota Electric argued that the number of hours at issue was so small (approximately three working days per year per affected employee) that those hours had been readily absorbed by the employees' normal duties, which had also been redefined between the 2010 and 2013 test years.

The Cooperative also pointed out that most of the 842 hours had been worked by salaried employees—including the chief executive officer, the vice-president of finance, and the corporate controller—who routinely work more than 40 hours a week and had devoted full-time efforts to regulated operations even when their service to the unregulated subsidiary was at its height.[14] The record shows that of the employees who billed hours to the subsidiary, two were hourly and 21 were salaried.[15]

The Department concurred with the Cooperative; the settlement agreement it had negotiated with the Cooperative did not reduce test-year payroll expense to reflect the reduction in support-hours billed to the Cooperative's subsidiary.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Cooperative had demonstrated through its undisputed testimony that its regulated operations were using the hours formerly devoted to the subsidiary and that no reduction in test-year payroll expense was warranted.

D. Commission Action

The Commission concurs with the Administrative Law Judge that the Cooperative's undisputed testimony shows that the 842 work hours formerly devoted to the subsidiary have been fully absorbed by regulated operations. As the Cooperative explained, hourly employees' workloads were adjusted to redirect those hours to regulated operations, and salaried employees continued to devote more than a 40-hour workweek to regulated operations. There is therefore no need or justification for a reduction to test-year payroll expense.

COST OF CAPITAL ISSUES

XI. Capital Structure and Overall Cost of Capital

Dakota Electric and the Department agreed on the Cooperative's capital structure, cost of debt, return on equity, and overall rate of return. The Administrative Law Judge concurred in their joint recommendation, as does the Commission.

[13] Tr. Evid. Hearing at 40 (Larson) (Dec. 18, 2014).

[14] The record shows that of the 23 employees who billed time to the unregulated subsidiary, 21 were salaried and two were hourly. Tr. at 40-41.

[15] Dakota Electric Reply Brief at 2.

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

Type of Capital	Composition	Cost	Weighted Cost
Equity	58.19 percent	4.28 percent	2.49 percent
Long Term Debt	41.81 percent	5.31 percent	2.22 percent
Total/ Weighted Cost	100.00 percent		4.71 percent
Return on Rate Base			6.47 percent

CLASS COST OF SERVICE STUDY ISSUES

XII. Class Cost of Service Study

A. Introduction

As required by rule, Dakota Electric's rate-case filing included a class cost of service study.[16] The purpose of a class cost of service study (CCOSS) is to determine, as accurately as possible, the costs of serving each customer class. While these costs cannot be determined with precision, it is critical that the cost study make both its underlying assumptions and the cost figures they yield as accurate and transparent as possible, because the Commission puts substantial weight on cost causation in determining what portion of the total revenue requirement each customer class should pay.

In a class cost of service study, costs are functionalized according to their various functions, including production, transmission, and distribution. Functionalized costs are classified as customer, demand, or energy costs according to how the costs are incurred. Because Dakota Electric does not own generation plants or transmission lines, the costs that can vary in its class cost of service study are related to the distribution system. The Cooperative used a minimum-size study to classify specific distribution accounts, separating distribution system costs into demand and customer components.

In its previous rate cases, Dakota Electric used a zero-intercept analysis to classify the cost of the customer component of its distribution facilities. In Dakota Electric's most recent general rate case in 2009, the OAG challenged the reliability of the zero-intercept method to classify customer and demand costs.[17] In that same case, the Department recommended, and the Commission directed, that the Cooperative be required to conduct in its next rate case a minimum-size analysis or provide an analysis with sufficiently robust data points to support the outcome of the zero-intercept method.

In response to the Commission's directive, the Cooperative conducted its cost study in this case using a minimum-size analysis. A minimum size analysis determines the minimum-size distribution equipment installed by constructing a hypothetical distribution system entirely from this minimum-sized equipment. The zero-intercept analysis is used to identify the portion of costs related to a hypothetical no-load, or zero-intercept, distribution system.

[16] Minn. R. 7825.4300.

[17] See *In the Matter of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota*, Findings of Fact, Conclusions of Law, and Order, Docket No. E-111/GR-09-175 (May 24, 2010).

The costs associated with the hypothetical minimum distribution system are classified as customer costs, while the costs of the utility's distribution system that exceed the system are classified as demand costs. For example, the average installed book cost of the minimum size pole currently installed is used to price all poles across the system.

A zero-intercept method is based on an estimated linear relationship between the cost of distribution equipment and the size of the equipment. For example, it is assumed that as the size of a conductor increases, the cost of the conductor increases commensurately.

The Department and Dakota Electric entered into a settlement agreement in this case that included agreement on use of the Cooperative's class cost of service study as a starting point for determining class revenue apportionment.

The OAG opposed the Cooperative's study and conducted its own cost study, a zero-intercept proxy method, which excluded material costs. Under the Cooperative's cost study, approximately 61.5 percent of costs were classified as customer costs, whereas under the OAG's cost study, approximately 38 percent of costs were classified as customer costs.

B. Positions of the Parties

1. Dakota Electric

Dakota Electric does not own generation plants or transmission lines and all costs that can vary in the class cost of service study are related to the distribution system. Dakota Electric stated that approximately 74 percent of its costs to serve members are wholesale costs (demand and energy), billed by Dakota Electric's wholesale power supplier, Great River Energy. The Cooperative's cost study allocated both wholesale power costs and distribution costs.

The Cooperative stated that in conducting its cost study, it adhered to the approach described in the 1992 *Electric Utility Cost Allocation Manual of the National Association of Regulatory Utility Commissioners* (NARUC Electric Manual).

Dakota Electric characterized the issue in dispute as a matter of how to classify certain distribution plant accounts and stated that using the zero-intercept method would have likely caused the same issues identified by the OAG in Dakota Electric's last rate case, in which it used a zero-intercept analysis. The Cooperative therefore used the minimum-size method to classify distribution accounts in this rate case.

In conducting its study, Dakota Electric used minimum-size equipment currently being installed for each plant account and provided a comparison of the weighted averages of the minimum-size study and of the zero-intercept study used in the Cooperative's last general rate case in 2009. The results of the minimum-size analysis showed that the weighted average minimum-size consumer classification (sum of minimum costs divided by sum of installed book costs) is 61.5 percent, compared to the weighted average zero-intercept consumer classification of 57.1 percent in Dakota Electric's 2009 general rate case. The Cooperative stated that its results are consistent with the NARUC Electric Manual, which states that the two methods will generally produce similar results, though the zero-intercept method generally produces a smaller customer component.

Dakota Electric argued that the OAG's analysis, a zero-intercept proxy method, was an alternative minimum system analysis that omitted the system, ignored the minimum cost of materials necessary to provide basic service and as a result, it underestimated the no-load cost of transformers and the other plant accounts subject to its analysis. The OAG's method was, in effect, a zero-system analysis. Dakota Electric stated that the OAG's method has never been proposed or adopted in any previous rate case and that it produced a weighted customer component of 38 percent, which is an outlier compared to the 61.5 percent from the minimum-size method and the 57.1 percent from the zero-intercept method last used by Dakota Electric.

Dakota Electric also disputed the OAG's claim that Dakota Electric's failure to include a demand adjustment in its cost study to account for demand costs undermines the study results. Dakota Electric stated that the NARUC Electric Manual does not require a demand adjustment and that the zero-intercept method is reasonably accurate in estimating customer costs with no load carrying capability. Because the results of the minimum-size method (61.5 percent) and the zero-intercept method (57.1 percent) are similar, the Cooperative believed that it was not necessary to apply a demand adjustment.

Dakota Electric also argued that the minimum-size analysis relies on the average book cost for each piece of plant and reflects the costs of installations over time to the present day, which means that a particular piece of plant could have been installed years ago or more recently and could therefore include an unusually low or high cost of a minimum-size plant, which could result in a less accurate demand adjustment.

2. The Department

The Department reached an agreement with Dakota Electric on its minimum-size cost study and recommended that the Commission use the cost study as a basis for determining revenue apportionment in this case. The Department opposed using the OAG's zero-intercept proxy cost study.

The Department stated that the Cooperative's study was conducted consistent with the description contained in the NARUC Electric Manual, and that the Cooperative's study used the smallest size equipment necessary to make service available and that the Cooperative used reasonable assumptions that reflect real-world size equipment.

The Department stated that the OAG's proxy method is inconsistent with the NARUC Electric Manual because it excluded all material costs related to making service available to customers. The Department argued that the proxy method is therefore not a reasonable method to use to separate the estimated costs of power delivery from the estimated costs of providing reliable service. To illustrate the point, the Department stated that the OAG model includes, for example, the cost of installing a minimum size pole without the cost of the pole. Without the equipment, service cannot be offered, and therefore the OAG's method does not allocate costs according to the minimum size distribution system necessary to serve customers.

The Department reasoned that the OAG's method is incomplete because it classifies customer costs at a level below a hypothetical no-load or zero-intercept level and because the method is not supported by the NARUC Electric Manual, which directs consideration of minimum material costs. The Department stated that the *amount* of load on a utility's system should not be considered in developing a minimum system, but if the *ability* to deliver load is wholly ignored, the system is not representative of a system capable of delivering energy.

The Department also stated that to address the OAG's concerns regarding a demand adjustment, it would be reasonable to require Dakota Electric, in its next rate case, to apply a demand adjustment to the results of a minimum-size analysis.

3. The OAG

The OAG opposed use of Dakota Electric's minimum-size analysis, arguing that the analysis generated excessive customer costs in excess of a no-load system, costs that should have been classified as demand costs.

The OAG argued that relying on Dakota Electric's cost study would disproportionally increase the burden on the residential class, which pays a larger share of costs classified as customer costs, because the study classified customer and demand costs incorrectly. Further, the OAG argued that Dakota Electric should have applied a demand adjustment to its cost study results to account for demand costs included in its analysis.

The OAG also disagreed with Dakota Electric's argument that no demand adjustment was necessary because the costs allocated to customers in Dakota Electric's 2009 cost study using a zero-intercept analysis (57 percent) and customer costs allocated using the minimum-size analysis (61.5 percent) were similar.

The OAG stated that there was no basis for Dakota Electric's comparison of the weighted averages of customer costs from the two analyses because the weighted average was not incorporated into the minimum-size cost study. Further, the OAG stated that the minimum-size and zero-intercept studies produced significantly different results for certain distribution accounts. Typically, customer costs are higher under a minimum-size analysis, but the Cooperative's minimum-size analysis produced lower customer costs for several distribution accounts than its previous zero-intercept analysis, calling into question the reasonableness of the results.

The OAG stated that its study results, which showed that 38 percent of costs are customer costs, more accurately reflect the costs of service for the various customer classes.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that Dakota Electric's minimum-size method for classifying distribution plant accounts is reasonably accurate and reflects the minimum-size equipment needed to serve customer load on the Cooperative's system.[18] The Administrative Law Judge therefore recommended that the Commission accept the Cooperative's study.

The Administrative Law Judge found that there was not sufficient evidence to support requiring Dakota Electric to include a demand adjustment in its next general rate case, particularly if the

[18] ALJ"s Report ¶ 111.

Cooperative performs a minimum system study using both the zero-intercept method and the minimum-size method.[19]

The Administrative Law Judge therefore recommended that the Commission require Dakota Electric, in its next rate case, to conduct its minimum study using the minimum-size study, supported by the zero-intercept method.[20]

D. Commission Action

The Commission concurs with the Administrative Law Judge, the Cooperative, and the Department that the minimum-size analysis conducted by the Cooperative is reasonable and should be used as a starting point in determining revenue apportionment and customer charges.

Dakota Electric conducted its analysis in accordance with the Commission's directive in the Cooperative's last general rate case in 2009, followed an established method for conducting the study as described in the NARUC Electric Manual, and used minimum sized equipment in its analysis.

The thrust of the OAG's opposition to the Cooperative's cost study is that a minimum-size method is less accurate than the zero-intercept method in calculating customer costs and that Dakota Electric did not apply a demand adjustment to account for demand costs. The OAG does not, however, argue that the Cooperative used a flawed methodology or failed to follow the NARUC Electric Manual.

The results of Dakota Electric's two cost studies – the zero-intercept method in the 2009 rate case and the minimum-size method in this case – show reasonably similar results. These results are based on sound and reliable methods for conducting cost studies, and the Commission concludes that the results are reasonable. The OAG acknowledged that its proxy method excluded material costs necessary to make service available to customers, an approach that is not recognized or recommended by the NARUC Electric Manual.

The Commission does not concur with the Administrative Law Judge that there is insufficient evidence in the record to require Dakota Electric to include a demand adjustment in its next general rate case. The Commission also declines to adopt the recommendation of the Administrative Law Judge to require Dakota Electric, in its next general rate case, to conduct a minimum system study by using the minimum-size method, supported by the zero-intercept method.

The Commission concurs with the Department that a demand adjustment would be a reasonable refinement to the minimum system analysis in the Cooperative's next rate case and will require that it include one. As the Department's witness noted, the minimum-size method can intrinsically include some demand-related costs associated with the load carrying capability of the equipment included in the study, and it is important to isolate demand costs as accurately as possible.[21]

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[19] *Id* at ¶ 113

[20] *Id*.

[21] Ex 303 at 7-8 (Ruzycki Surrebuttal).

The goal of any cost study is to predict, as accurately as possible, the costs of serving each customer class. Applying a demand adjustment to the results of the cost study increases the precision and accuracy by more exactly identifying customer and demand costs. The Commission concludes that requiring Dakota Electric, in its next general rate case, to include a demand adjustment will be an effective method for increasing accuracy and that it is therefore not necessary to require the Cooperative to conduct two cost studies in its next rate case.

For these reasons, the Commission will accept the Cooperative's cost study as a starting point for revenue apportionment and will direct the Cooperative to include a demand adjustment in its next general rate case.

RATE DESIGN ISSUES

XIII. Class Revenue Apportionment

A. Introduction

In every rate case, the new revenue requirement must be apportioned among the customer classes. This raises the issue of interclass revenue responsibility built into the rate structure – what portion of the revenue requirements should be recovered from each class?

In this case, the Cooperative and the Department reached agreement on a proposed revenue apportionment, while the OAG proposed its own revenue apportionment.

B. The Positions of the Parties

1. The Cooperative and the Department

Dakota Electric and the Department concurred on a proposed revenue apportionment, as contained in the settlement agreement. The apportionment was based on the Cooperative's class cost of service study as a starting point, with modifications for non-cost factors, such as avoiding rate shock and ability to pay. In evaluating revenue apportionment, the Department considered the following four principles: rates should allow recovery of the revenue requirement; rates should promote efficient use of resources; rates should change gradually to prevent rate shock; rates should be understandable and easy to administer.

The following table shows the rate changes that would occur if the revenue apportionment were based on the results of the class cost of service study, as well as the rate changes agreed to by the Cooperative and the Department:[22]

[22] Ex. 101 at 31 (Larson Direct) and Ex. 305 at 3 (Peirce Surrebuttal).

Class	(A) CCOSS	(B) Proposed
Residential & Farm	2.85%	2.79%
Small General Service	7.47%	3.50%
Irrigation	2.03%	2.00%
General Service	(0.33)%	0.27%
C&I Interruptible	2.33%	2.25%
Lighting	1.12%	1.02%

Under the proposed revenue apportionment, the Residential and Farm Service class and the Small General Service class remain below cost. The Cooperative and the Department agreed that these increases were reasonably limited without unreasonably burdening other classes.

2. The OAG

The OAG objected to the proposed revenue apportionment agreed to by the Cooperative and the Department, stating that it was based on an inaccurate class cost of service study and that the Cooperative had not made necessary adjustments to account for the inaccuracies.

The OAG argued that the increase to the Residential Class was unreasonably high and should be reduced to further the important policy goal of limiting such increases because some residential customers are unable to absorb any rate increase. The OAG recommended using the results of its class cost of service study as a basis for determining revenue apportionment, stating that its cost study was more reliable than the Cooperative's cost study.

The following table shows the difference in the resulting rate increases between the proposed revenue apportionment of the OAG and the proposed revenue apportionment as agreed to between the Cooperative and the Department in the settlement agreement.[23]

	Total System	Resid. & Farm	Sm. Gen'l. Svc.	Irrigation	Gen'l. Svc.	C & I Interrupt.	Lighting
OAG	2.11%	1.9%	2.61%	2.8%	1.91%	3.41%	1.5%
Settlement	2.11%	2.79%	3.5%	2.0%	0.27%	2.25%	1.02%

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the OAG's proposal was based on an unsupported cost study and that it overemphasized the balancing of rate increases among the various classes and underemphasized the importance of considering the costs related to serving those classes.

[23] ALJ's Report ¶ 128.

She concluded that the proposal contained in the settlement agreement that assigned a 2.79 percent increase to the Residential and Farm Service class would not constitute rate shock and represented an amount that would bring this class closer to cost. She also concluded that the increase to the General Service class proposed by the OAG would significantly increase their rates, causing them to further subsidize costs to other classes without reasonably bringing classes closer to cost.

She recommended that the revenue apportionment agreed to by the Cooperative and the Department is just and reasonable and supported by the record. She therefore recommended that the Commission adopt the revenue apportionment contained in the settlement agreement.

D. Commission Action

The Commission concurs with the Administrative Law Judge, the Cooperative, and the Department that the proposed revenue apportionment in the settlement agreement best balances cost and non-cost factors and will therefore authorize its use.

As discussed above, the OAG's proposal is based on its zero-intercept proxy analysis, the results of which allocated 38 percent of costs to customers, based on a distribution system that could not make service available to customers. The Commission also concurs with the Administrative Law Judge that the proposed increase to the Residential and Farm Service class avoids rate shock by bringing this class closer to cost with a moderate increase, while avoiding unreasonable increases to other classes.

For these reasons, the Commission will authorize use of the revenue apportionment in the settlement agreement, which reasonably balances the interest of bringing rates closer to cost while avoiding wide swings that could result in rate shock.

XIV. Residential and Farm Service Class and Small General Service Class Customer Charges

A. Introduction

Dakota Electric's customers pay both an energy charge and a customer charge. The energy charge is a per-kWh charge based on electricity use. The customer charge is a fixed monthly charge assessed without regard to usage level. It is designed to help recover fixed customer-related costs such as the cost of billing, meters and meter reading, and the minimum distribution facilities required to provide service.

Dakota Electric and the Department reached an agreement on proposed increases to the fixed monthly charges. The OAG opposed any increase in the customer charge to the Residential and Farm Service and the Small General Service classes.

The proposed increases agreed to by the Department and the Cooperative are shown in the DOC Proposed Charge column as follows:[24]

[24] Ex. 304 at 10 (Peirce Direct).

Class	Customer Costs	Current Customer Charge	DEA Proposed Charge	DOC Proposed Charge
Residential & Farm	$23.39	$8.00	$10.00	$9.00
Residential & Farm Demand Control		$11.00	$13.00	$12.00
Residential & Farm Time of Day		$11.00	$13.00	$12.00
Residential TOD – New Schedule 55		-	$13.00	$12.00
Irrigation	$62.56	$24.00	$30.00	$30.00
Small Gen. Service	$33.28	$10.00	$14.00	$14.00
General Service	$69.45	$28.00	$34.00	$34.00
General Service – TOD		$30.00	$36.00	$36.00
C&I Interruptible	$188.92	$80.00	$110.00	$110.00

B. Positions of the Parties

1. The OAG

The OAG objected to any proposed increase in the fixed customer charge for the Residential and Farm Service class and the Small General Service class.

The OAG calculated the monthly customer charge for serving the residential class, excluding the cost of the primary line, at $11.41. The OAG argued keeping this charge at $8.00 benefits the majority of low-income customers because when customer charges are low, costs are recovered though the energy charge, which customers can reduce by reducing their usage. The OAG stated that leaving the customer charge at $8.00 benefits the majority of low-income customers receiving low-income home energy assistance (LIHEAP) because they consume lower levels of energy.

The OAG also argued that placing more of the cost of service into the volumetric charge, instead of into the monthly fixed customer charge, provides greater incentives to customers to conserve energy because they can reduce their bills by using less electricity.

The OAG also opposed the increase to the Small General Service class, arguing that it fails to encourage conservation and that it does not reduce intra-class subsides as claimed by the Cooperative and the Department.

2. Dakota Electric

Dakota Electric and the Department reached an agreement on customer charges that would increase the customer charge for the Residential and Farm Service class from $8.00 to $9.00. The agreement increases the charge for the Small General Service class from $10.00 to $14.00.

Dakota Electric stated that its class cost of service study showed that the monthly cost of service to the Residential and Farm Service class is $23.39 and that the monthly cost of service to the Small General Service class is $33.28. The Cooperative stated that the costs, excluding the primary line, for these classes are $11.65 and $18.94, respectively and that it is undisputed that its proposed customer charges remain below cost.

Dakota Electric stated that its proposed customer charges contain moderate and gradual increases that move charges closer to cost, reduce intra-class subsidies, and more accurately recover costs, consistent with ratemaking policy.

3. The Department

The Department stated that when customer costs are not recovered through the monthly fixed charges, those costs are recovered from the volumetric (energy) charges a customer incurs for electricity consumed. Customers who use more energy incur higher energy charges and in effect subsidize customers in the same class who have lower usage.

The Department calculated the monthly costs of service, including the primary line, at $23.39 for the Residential and Farm Service class and $33.28 for the Small General Service class. In response to the OAG's claims that the monthly cost of serving these two classes should not have included costs of the primary line when estimating intra-class subsidies, the Department argued that the cost of the primary line is a customer cost and is necessary to bring service to a customer and that failing to recover primary line costs through a fixed charge means other customers pay those costs through their energy charges.

To reduce intra-class subsidies, the Department supported a one dollar increase to the residential class, which reduces the subsidies paid by low-income, higher-usage customers. The average usage of Dakota Electric's LIHEAP customers is 1,073 kWh per month. The Department calculated that customers using 750 kWh in a month have reached a breakeven point where their charges reflect the cost of serving them. Low-income customers using an average of 1,073 kWh per month, however, pay $6.14 per month above their costs, subsidizing other residential customers. The Department therefore supported the increase in the customer charge from $8.00 to $9.00 for the residential class.

The Department also stated that the joint proposal is reasonably designed to promote energy conservation because customers can decrease their energy bills by using less energy, and they can participate in energy programs (such as rebates), the costs of which are included in the energy charge, signaling customers to use less energy. Further, the Department stated that conservation does not entirely offset fixed costs for being connected to the distribution system.

The Department argued that the settlement agreement reasonably balances the goal of moderating changes in rate design and bringing customer charges closer to cost, while limiting unintended consequences on low-income, higher usage customers.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with Dakota Electric and the Department that lower fixed monthly charges ultimately result in higher volumetric charges, causing higher usage customers to subsidize other customers within the same class who use less electricity.[25] She concluded that the closer a fixed customer charge is to the actual cost of providing service, the less the volumetric charge will be used to subsidize fixed costs. Higher fixed charges that are closer to the actual cost of utility service, on the other hand, are more accurate and are more fair, financially, for customers who use more electricity.

She concluded that at the current $8.00 customer charge, some low-income higher-usage customers subsidize low-usage customers, on average, at a rate of $6.14 per month and that these low-income high-usage customers are more harmed than low-income, low-usage customers who would pay an additional $1.00 per month under the proposed increase, which would lower the intra-class subsidy.

She also found that a $1.00 increase in the fixed customer charge for the Residential and Farm Service class will leave a portion of fixed customer costs unpaid and that no one disputed that fact. She also concluded that a $1.00 increase gradually brings rates closer to cost without increasing intra-class subsidies or discouraging conservation. She further concluded that energy conservation incentives will continue to drive customers to reduce their energy consumption, resulting in lower energy charges.

She recommended that the Commission approve the proposed fixed customer charges, except the increase to the Small General Service class. She recommended that in lieu of a $4.00 increase (from $10.00 to $14.00) to the customer charge, the Commission instead increase the charge by $2.00 and adjust the volumetric charge accordingly. She concluded that this would avoid an abrupt increase that could result in rate shock to this class of customers and would more strongly encourage conservation, which affects volumetric charges.

D. Commission Action

The Commission concurs with the Administrative Law Judge, the Cooperative, and the Department that moderate increases to the customer charge, as proposed in the settlement agreement, are reasonable, although the Commission disagrees with the recommendation of the Administrative Law Judge to reduce the proposed increase to the Small General Service class from $14.00 to $12.00.

The Commission does not concur with the Administrative Law Judge that the increase in the Small General Service customer charge should be limited to $2.00, instead of the $4.00 proposed in the settlement agreement. The ALJ was concerned that raising the monthly charge from $10.00 to $14.00 might fail to give adequate consideration to the principles of gradualism, avoiding rate shock, and encouraging conservation.

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[25] ALJ's Report ¶ 165.

While the Commission concurs on the importance of these principles, it does not believe the proposed $4.00 increase jeopardizes them. Since the current customer charge for this class recovers less than a third of the cost of service, the need to reduce intra-class subsidies is even clearer here than for the Residential and Farm Service class.[26] And since this class is a commercial class, straitened household budgets do not weigh as heavily in balancing intra-class equity and existing rate expectations. Further, rebalancing the customer charge and usage portions of commercial customers' bills should not create a disincentive to conservation, as these customers are likely to be in a position to analyze and manage their energy consumption.

The Commission therefore concludes the proposal contained in the settlement agreement is an appropriate adjustment that balances the need to recoup the costs of serving the classes and minimize intra-class subsidies, with the need to encourage conservation and avoid rate shock.

The Commission will therefore approve the increases to the fixed monthly customer charges as proposed in the settlement agreement.

FINANCIAL SCHEDULES AND COMPLIANCE

XV. Overall Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a total gross revenue deficiency of $4,010,171 for the test year, as shown below:

Revenue Deficiency Summary
Test Year Ending December 31, 2013

Line No.			
1	Average Rate Base	$	171,181,006
2	Rate of Return		6.47%
3	Required Operating Income	$	11,078,195
4	Less: Non-Operating Income	$	126,258
5	Net Operating Income Required	$	10,951,937
6	Operating Income	$	6,941,766
7	Revenue Deficiency	$	4,010,171

[26] The cost of service for the Residential and Farm Service class is $23.39, and for the Small General Service class, $33.28.

B. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the 2013 test year is $171,181,006, as shown below:

Rate Base Summary
Test Year Ending December 31, 2013

Line No.		
1	Utility Plant in Service	$ 258,940,146
2	Construction Work in Progress	$ 5,053,958
3	Less: Accumulated Depreciation	$ 104,345,103
4	Net Plant	$ 159,649,001
5	Materials and Supplies	$ 5,229,359
6	Working Capital	$ 6,861,992
7	Subtotal	$ 171,740,352
8	Less: Consumer Deposits	$ 559,346
9	TOTAL RATE BASE	$ 171,181,006

C. Operating Income Summary

Based on the above findings, the Commission concludes that the appropriate operating income for the test year under present rates is $6,941,766, as shown below:

Operating Income Summary
Test Year Ending December 31, 2013

Line No.			
	OPERATING REVENUES		
1	Rate Schedules	$	198,872,121
2	Other		692,126
3	Total Operating Revenue	$	199,564,247
	OPERATING EXPENSES		
4	Cost of Purchased Power	$	149,982,061
5	Transmission - O & M		-
6	Distribution – Operation		7,219,891
7	Distribution - Maintenance		6,200,858
8	Consumer Accounts		4,303,362
9	Consumer Service & Information		3,193,367
10	Sales		-
11	Administrative & General		9,443,656
12	Depreciation & Amortization		8,497,932
13	Taxes - Property		3,700,450
14	Taxes – Other		-
15	Other Interest Expense		283,445
16	Other Deductions		(202,541)
17	Total Operating Expenses	$	192,622,481
18	NET OPERATING INCOME	$	6,941,766

XVI. Compliance Filing Required

The Commission will require the Cooperative to make a compliance filing within 30 days of the date of this order showing the final rate effects of the decisions made here. The Commission will establish a brief comment period to give interested persons a chance to review and comment on that filing.

ORDER

1. Dakota Electric Association is entitled to increase Minnesota jurisdictional revenues by $4,010,171 to produce jurisdictional total retail-related revenue of $203,574,418 for the test year ending December 31, 2013.

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. For purposes of clarity, the Commission modifies ALJ Finding 63, as set forth below:

> 63. DEA requested recovery of increased costs in payroll expenses, including an annualization adjustment covering 16 employee positions vacant for a portion of the test year (2013), as well as the addition of one new employee position in 2014. According to DEA, it paid out $643,269 in actual wages for the 16 partially filled positions in 2013 instead of $1,040,494 in wages that would have been paid if the positions had all been filled for the entire year. DEA also added one new position (Powerline Design Technician) in 2014, which has an annual wage of $68,210. Based on the new additional position and total wages necessary to fully fund the 16 positions for an entire year, DEA requested an increased annualization adjustment of $465,435 and associated benefits.

4. For purposes of clarity, the Commission modifies ALJ Finding 64, as set forth below:

> 64. ~~The OAG, however, valued DEA's annualization adjustment at $690,427 based on the wages claimed by DEA plus the OAG's calculation of the benefit expense for the 16 partially filled positions ($589,244) and one new added position ($101,183).~~ The OAG objected to DEA's annualization adjustment for two reasons. First, the OAG claimed DEA failed to show the increase is "a known and measurable change" because DEA's request covers positions "it hopes to fill or to remain filled, rather than positions ... it knows will be filled." The OAG claimed the additional "incremental position" for a new Powerline Design Technician "appears to inflate compensation expenses." Second, the OAG argued the requested increase cannot be reconciled with the general trend of DEA's payroll expense, which has been relatively flat for the past three years. Between 2010 and 2013, the OAG claimed the average change in DEA's annual payroll expense has been less than one percent as detailed in the table below: [Footnotes and table omitted.]

5. The Commission strikes ALJ Findings 112 and 113, as set forth below:

> ~~112. In addition, the Administrative Law Judge recommends that the Commission require DEA to conduct its minimum system study in its next rate case by using the minimum-size method, supported by the zero- intercept method.~~
>
> ~~113. The Administrative Law Judge finds that there is insufficient evidence in the record to determine that a demand adjustment should be required in DEA's next rate proceeding, particularly if DEA performs its minimum system study using both the zero-intercept and the minimum- size methods of analysis. Therefore, the Administrative Law Judge does not recommend that the Commission require DEA to incorporate a demand adjustment into its next minimum-size method analysis.~~

6. The Commission strikes ALJ Finding 170, set forth below, and authorizes a $14.00 monthly customer charge for the Small General Service customer class.

> ~~170. With regard to DEA's proposal to increase the fixed customer charge for the Small General Service class by 40 percent (or $4.00), the Administrative Law Judge finds this proposal fails to adequately consider the principles favoring gradual increases in fixed customer charges, avoiding rate shock and encouraging reasonable efforts toward conservation. While the parties provided little testimony specific to this customer class, the Administrative Law Judge notes that a 40 percent increase in the fixed customer charge is not gradual and could constitute rate shock. The increase is especially troubling given that the proposed increase in this class's volumetric charge is only 2 percent, an amount that, if increased, could support conservation goals more strongly. While the Administrative Law Judge recognizes the importance of bringing fixed customer charges closer to each class's fixed cost of service, this proposal increases the Small General Service class too abruptly. The Administrative Law Judge respectfully recommends that the Commission approve a fixed customer charge of $12.00, which would be a 20 percent increase for the Small General Service class, and adjust the volumetric charge accordingly.~~ [Footnotes omitted.]

7. Dakota Electric Association shall include in the initial filing of its next rate case work papers for both the purchased-power revenue and purchased-power expense amounts included in the pro forma test-year financial schedule.

8. Dakota Electric Association shall include a demand adjustment in the Class Cost of Service Study submitted in its next rate case.

9. Within 30 days of the date of this order, the Cooperative shall make the following compliance filings:

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

      i. Breakdown of Total Operating Revenues by type.

      ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to

         - Total revenue by customer class;

         - Total number of customers, the customer charge, and total customer-charge revenue by customer class; and

         - For each customer class, the total number of energy- and demand-related billing units, the-per unit energy and demand cost of energy, and the total energy- and demand-related sales revenues.

      iii. Revised tariff sheets incorporating authorized rate-design decisions.

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

   b. A revised base cost of energy, supporting schedules, and resource- and tax-adjustment tariffs to be in effect on the date final rates are implemented.

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

   d. A schedule detailing the Demand-Side Management (DSM) and Conservation Recovery tracker balance at the beginning of interim rates, the revenues (both base and the Resource and Tax Adjustment rate recovery) and costs recorded during the period of interim rates, and the DSM & Conservation Recovery tracker balance at the time final rates become effective.

   e. If final authorized rates are lower than interim rates, a proposal to make refunds of interim rates to affected customers, consistent with the Commission's decision in this proceeding.

10. Any comments on compliance filings shall be filed within 20 days of the date of the compliance filing. Comments are not necessary on the Cooperative's proposed customer notice.

11. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf

Daniel P. Wolf
Executive Secretary

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