BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
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FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE APPLICATION OF DAKOTA ELECTRIC ASSOCIATION FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN MINNESOTA	MPUC Docket No. E-111/GR-14-482 OAH Docket No. 80-2500-31796

REPLY BRIEF OF THE MINNESOTA DEPARTMENT OF COMMERCE

Dated: January 30, 2015

Respectfully submitted,

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INTRODUCTION

The Minnesota Department of Commerce, Division of Energy Resources, Energy Regulation and Planning Unit (the "Department" or "DOC") respectfully submits this Reply Brief to Administrative Law Judge ("ALJ") LauraSue Schlatter and the Minnesota Public Utilities Commission ("Commission"). Filed separately are Proposed Findings of Fact pertaining to the application for a general rate increase filed by the Dakota Electric Association ("DEA," "Cooperative," or the "Association").

As discussed in its Initial Brief, the Department and DEA reached an agreement on all issues in this matter. DOC Initial Br. at 9–10. DEA and the Department resolved certain issues through pre-filed testimony, and the remainder of the disputed issues by the evidentiary hearing. DEA ultimately concurred with the Department's final recommendations that it presented in pre-filed testimony, which is memorialized in a Settlement Agreement and an Amendment to the Settlement Agreement. DEA Ex. 128, 128A (collectively the "Settlement Agreement"). DEA and the Department continue to agree that this resolution will result in reasonable and just rates for all DEA customers and recommend that the Commission approve DEA's Petition based upon the resolution of issues described in the Settlement Agreement. The only issues that remain in dispute are issues that the Office of the Attorney General, Antitrust and Utilities Division's ("OAG-AUD") has raised. In this Reply Brief, the Department responds to the OAG-AUD's Initial Brief, but the Department continues to rely on the extensive analyses and recommendations set forth in its Initial Brief and its Proposed Findings of Fact.

ARGUMENT

I. THE DEPARTMENT'S RESPONSE TO OAG-AUD'S INITIAL BRIEF: RATE DESIGN

A. The Department's Rate Design Recommendations Represent a Balancing of Important Policy Goals

It is important to fully consider the effects of rate-design policies on all customers when determining whether to increase customer charges. DOC Initial Br. at 50. In advocating for no change to DEA's current residential and small business customer charges, OAG-AUD states that it would be unfair to low-income, lower-use customers to increase customer charges and that it would not promote energy conservation. OAG-AUD Initial Br. at 23–26.

The Department shares OAG-AUD's important concerns. *See* DOC Initial Br. at 53–57. When setting rates, however, the Commission must often balance myriad concerns, including those OAG-AUD has raised, in order to arrive at just and reasonable rates for all regulated utility customers. *Id.* at 50, 57. Recognizing that DEA has not sought rate increases in five years, the Department weighed the reasonableness of updating DEA's rates by sending appropriate price signals to its customers on the cost of service. *Id.* at 50–51. The Department weighed the reasonableness of limiting intra-class subsidies that occur when some customers within a class do not pay their respective costs of service, which can be unfair to other customers who may pay more than their full cost of service. *Id.* at 50–53. The Department also weighed the reasonableness and requirement of encouraging energy conservation. *Id.* at 53. In addition, the Department weighed the effect of its proposed rate design on low-income customers that not only use a lower amount of electricity, but those that may use a higher amount of electricity. *Id.* at 54–57. In the end, the Department recommends a modest and balanced increase in the residential and small business customer charges, to which DEA has agreed. DOC Initial Br. at

49; DEA Ex. 128 at 13 (Settlement Agreement). The Department's recommended rate design will result in just and reasonable rates for all DEA customers.

B. Subsidies Relevant to Determining a Reasonable Customer Charge

In its Initial Brief, OAG-AUD stated: "DEA and the Department each fail to consider any intra-class subsidies other than those between high-use and low-use customers, or that the 'customer costs' produced by the CCOSS are based on an average." OAG-AUD Initial Br. at 27. Regarding the determination of a reasonable customer charge, it is necessary to evaluate the customer usage above and below the so-called breakeven point to assess how customers within the class would be affected. DOC Initial Br. at 50–51. If customer costs (the costs of connecting a customer to the system) exceed the customer charge, as residential costs do, it is necessary to estimate the breakeven point of the amount of electricity where a customer must use for DEA to recover the remaining customer costs through the energy charge. *Id.* Doing so indicates which customers would pay more or less under different rate designs. Limiting the amount of customer costs that DEA collects through the energy charge through a modest increase in the customer charge makes DEA's rates more fair to all customers by moving slightly closer to cost and reducing the amount that higher-use customers subsidize lower-use customers.

II. THE DEPARTMENT'S RESPONSE TO OAG-AUD'S INITIAL BRIEF: CCOSS

A. The OAG-AUD's Minimum-System Study Does Not Reasonably Reflect All of the Costs of Being Able to Deliver Power to Customers

In its Initial Brief, OAG-AUD stated the following: "The minimum system estimates the hypothetical, minimum distribution system *necessary simply to provide service* to customers, without consideration of a customer's demand." OAG-AUD Initial Br. at 14 (emphasis added). The Department agrees. DOC Initial Br. at 38. But OAG-AUD's minimum-system study, the zero-intercept proxy, does not estimate the "minimum distribution system necessary simply to provide service to customers . . . ." *Id.* at 41. At the evidentiary hearing, OAG-AUD witness Mr. Nelson provided the following answer regarding whether the zero-intercept proxy could provide service to DEA customers:

> Q. I'm asking if your zero-intercept proxy, your minimum system, would be capable of delivering any service to customers of Dakota Electric?
> A. It would not be able to deliver capacity or any energy, yeah.

Tr. Vol. 1 at 99 (Nelson). Because OAG-AUD's zero-intercept proxy does not reasonably reflect all of the costs of being able to deliver power to customers, it is not a reasonable method to separate the estimated costs of power delivery from the estimated costs of providing reliable service. DOC Initial Br. at 41. Therefore, the Department continues to recommend that the Commission adopt DEA's minimum-system study, which does reasonably classify customer costs from demand costs in its distribution plant accounts and would be able to serve its customers should they desire service.

B. The Zero-Intercept Method and the Minimum-Size Method Should Result in Similar Classifications of Distribution Plant Accounts

According to the 1992 *Electric Utility Cost Allocation Manual of the National Association of Regulatory Utility Commissioners* ("NARUC Electric Manual"), there are two common methods for classifying distribution plant accounts: 1) the minimum-size method; and 2) the zero-intercept method. DOC Ex. 311 at 90–96 (NARUC Electric Manual). The NARUC Electric Manual states the following regarding the zero-intercept: "In most instances, it is more accurate, although the differences may be relatively small." DOC Ex. 311 at 92 (NARUC Electric Manual). Therefore, the NARUC Electric Manual indicates that the two methods should produce similar results. *Id.*

In its Initial Brief, OAG-AUD stated the following regarding the minimum-size and zero-intercept methods: "While each of these methods designs a hypothetical minimum distribution system, they are conceptually different from one another and, even if performed correctly, will likely lead to different classifications of customer and demand costs."[1] OAG-AUD Initial Br. at 15. While "different classifications" may be present in the results for classification of distribution plant accounts under the minimum-size and zero-intercept methods, the record demonstrates that any "different classifications" are generally small. DOC Ex. 302 at 4 (Ruzycki Rebuttal); DEA Ex. 125 at Workpaper 21 at 4 (Larson Direct); DOC Ex. 311 at 92 (NARUC Electric Manual).

C. The Mathematical Justification for OAG-AUD's Zero-Intercept Proxy Is Disputed

OAG-AUD stated in its Initial Brief that Mr. Nelson's mathematical justification for the OAG's proxy is undisputed. OAG-AUD Initial Br. at 21. The mathematical justification for OAG-AUD's zero-intercept proxy is much in dispute, however. DOC Initial Br. at 40–44; DEA Initial Br. at 8–10. The Department is concerned that OAG-AUD's method considers only the costs of installing a minimum size pole, but does not, however, include equipment costs of any equipment, even the smallest size pole that would need to be installed, let alone other facilities needed to be able to deliver power to DEA's customers. DOC Ex. 302 at 6 (Ruzycki Rebuttal); Tr. Vol. 1 at 96 (Nelson). The OAG-AUD's method classifies customer costs at a level below a hypothetical no-load or zero-intercept situation, and therefore, the proposed method does not adequately estimate the costs of a system that is capable of delivering power to DEA's customer-members. Tr. Vol. 1 at 99–100 (Nelson); DOC Ex. 302 at 6 (Ruzycki Rebuttal). As indicated

[1] OAG-AUD stated in its Initial Brief that the NARUC Electric Manual indicates that the minimum-size method "should" produce a higher classification of customer costs than the zero-intercept method. The Department's reading of the NARUC Electric Manual is that such results "generally" are higher, but that the zero-intercept method may produce inconsistent results. DOC Ex. 311 at 91, 95 (NARUC Electric Manual).

above, it is not a reasonable method to classify customer costs and demand costs in DEA's distribution plant accounts.

D. DEA's 2009 Zero-Intercept Method Results Are the Only Zero-Intercept Method Results in the Record

In its Initial Brief, OAG-AUD states the following: "Because the OAG's proxy produces results that are equivalent to the more precise zero-intercept analysis, the OAG's CCOSS is reasonable and should be used to inform the company's revenue apportionment." OAG-AUD Initial Br. at 21. OAG-AUD's zero-intercept proxy classifies 38.3% of distribution plant as customer costs, whereas DEA's own zero-intercept method, which is the only complete zero-intercept method in the record, classifies 57.1% of distribution plant as customer costs. DOC Initial Br. at 41; DEA Ex. 125 at Workpaper 21 at 4 (Larson Direct). Clearly, OAG-AUD's zero-intercept proxy and DEA's zero-intercept method have not produced similar results. This difference is due to the fact that the zero-intercept proxy does not include the equipment needed to deliver energy to consumers.

For this case, DEA implemented a minimum-size methodology to classify specific distribution accounts. DOC Ex. 301 at 6 (Ruzycki Direct). Because the Commission had some concerns about the accuracy of DEA's zero-intercept method that it conducted in its 2009 rate case, the Commission required DEA to complete a minimum-system study by using the minimum-size method in its next rate case:

> Dakota Electric shall, in its next rate case, either use the minimum–size method to classify Distribution accounts, or provide such an analysis to support the outcome of the zero-intercept method.

In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-111/GR-09-175, Findings of Fact, Conclusions of Law, and Order at 23 (May 24, 2010). DEA showed that the minimum system study in this rate case—which estimated a 61.5% weighted customer component of the distribution system—is only 4.4 percentage points higher than the 57.1% weighted customer component from the previous rate case in which a zero-intercept methodology was used. DOC Ex. 302 at 4 (Ruzycki Rebuttal).

Given its closeness in proximity to DEA's zero-intercept study results, DEA's minimum-size method confirms the reasonableness of DEA's classification of distribution plant accounts. DOC Initial Br. at 44. OAG-AUD's zero-intercept proxy claims to produce results close to that of a zero-intercept study that does not exist in the record. As there is no one correct method for classifying distribution plant accounts, the Department would not be opposed to an alternative method if it provided a clear, logical process and it relied on realistic assumptions of a system that is capable of delivering energy to consumers, which is a requirement of a theoretical minimum system. DOC Ex. 302 at 6-7 (Ruzycki Rebuttal). Given that OAG-AUD's zero-intercept proxy does not do so and thus represents an outlier in the record, the Department does not recommend its adoption in this case. *Id.*

CONCLUSION

The Department respectfully requests a recommendation from the Administrative Law Judge and an Order from the Commission determining that the rates filed by DEA have been shown to be just and reasonable, as reflected in the parties Settlement Agreement and for the reasons discussed in the Department's Initial Brief. The Department requests that the Commission establish rates consistent with the principles, analyses and recommendations as addressed in the Department's testimony and Initial Brief, the Settlement Agreement, and the parties' Issue Matrix.

Dated: January 30, 2015 Respectfully Submitted,

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IN THE MATTER OF THE APPLICATION OF DAKOTA ELECTRIC ASSOCIATION FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN MINNESOTA

MPUC Docket No. E-111/GR-14-482
OAH Docket No. 80-2500-31796

PROPOSED FINDINGS OF FACT OF THE MINNESOTA DEPARTMENT OF COMMERCE

Dated: January 30, 2015

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INTRODUCTION

The Minnesota Department of Commerce, Division of Energy Resources, Energy Regulation and Planning Unit ("Department" or "DOC") respectfully submits these Proposed Findings of Fact to assist the Administrative Law Judge ("ALJ") and the Minnesota Public Utilities Commission ("Commission") regarding the application for a general rate increase filed by Dakota Electric Association ("DEA," "Dakota Electric," the "Association" or the "Cooperative"). The Department's Initial Brief was the principal document used to create these Proposed Findings of Fact such that the headings are left intact to assist the reader.

PROCEDURAL HISTORY

1. On July 2, 2014, DEA filed a general rate case petition ("Petition") that requested an annual increase of approximately $4,189,000, or about 2.1%, based on a historical 2013 test year. DEA requested an interim rate increase of approximately $2,982,000, or 1.5%, effective September 11, 2014.

2. On July 7, 2014, the Commission issued a Notice of Comment Period on Completeness and Procedures. The Commission scheduled an initial comment period to close on July 14, 2014 and a reply comment period to close on July 21, 2014.

3. On July 14, 2014, the Department submitted comments recommending that the Commission accept DEA's filing as substantially complete and refer the matter to the Office of Administrated Hearings ("OAH") for a contested case proceeding.

4. On August 21, 2014, the Commission met to consider the matter.

5. On August 29, 2014, the Commission issued a Notice and Order for Hearing, an Order Accepting Filing and Suspending Rates, and an Order Setting Interim Rates. The Commission referred the matter to OAH for a contested case proceeding. The Commission did not extend the statutory ten-month period and ordered that the ALJ submit a final report on or before March 2, 2015.

6. In its Order Setting Interim Rates, the Commission found that DEA's interim rate request of approximately $2,982,432, or 1.5%, was less than the amount authorized by the interim rates statute, but determined that authorizing the interim rate request was in the public interest and reasonable because it is sufficient to cover its operations. The Commission

approved DEA's interim rate increase request to begin with DEA's Cycle 1 billings in October, 2014.[1]

7. In its Notice and Order for Hearing, the Commission ordered that the parties address the following issues:

a. Is the test year revenue increase sought by the Association reasonable or will it result in unreasonable and excessive earnings by the Association?

b. Is the rate design proposed by the Association reasonable?

c. Are the Association's proposed capital structure, cost of capital, and return on equity reasonable?

8. On September 9, 2014, ALJ LauraSue Schlatter held a prehearing conference.

9. On September 15, 2014, the ALJ issued the First Prehearing Order, which set procedures for parties in the case and established the following schedule:

Milestone	Timing
Intervention Deadline	October 2, 2014
Direct Testimony, Intervenors	October 30, 2014
Public Hearings	December 2, 2014
Rebuttal Testimony	November 20, 2014
Surrebuttal Testimony	December 8, 2014
Deadline for Public Comments	December 12, 2014
Telephonic Status Conference	December 12, 2014
Evidentiary Hearing	December 18-19, 2014
Applicant's Issues Matrix	January 9, 2015
Initial Briefs	January 20, 2015
Reply Briefs, Proposed Findings of Fact, and Comments on Issues Matrix	January 30, 2015
ALJ Report	March 2, 2015

[1] DEA had waived its right to put interim rates into effect on August 1, 2014.

In addition, the ALJ granted the Office of the Attorney General – Antitrust and Utility Division's ("OAG-AUD") petition to intervene.

10. On October 30, 2014, the Department and OAG-AUD filed Direct Testimony in accordance with the ALJ's First Prehearing Order.

11. On November 20, 2014, DEA, the Department, and OAG-AUD filed Rebuttal Testimony in accordance with the ALJ's First Prehearing Order.

12. On December 2, 2014, the ALJ held two public hearings, the first being held in Apple Valley, MN at 2:00 p.m. and the second being held in Farmington, MN at 7:00 p.m.

13. On December 8, 2014, DEA, the Department, and OAG-AUD filed Surrebuttal Testimony in accordance with the ALJ's First Prehearing Order.

14. On December 11, 2014, the parties met to discuss potential settlement of issues.

15. On December 12, 2014, the ALJ convened a telephonic prehearing conference to discuss procedures for the evidentiary hearing and the parties' settlement efforts.

16. On December 18, 2014, the ALJ held a one-day evidentiary hearing in the Commission's small hearing room.

17. At the evidentiary hearing, DEA and the Department entered into a settlement agreement, which resolved all remaining disputed issues between DEA and the Department from pre-filed testimony. The parties offered and the ALJ entered the settlement agreement into the record as Exhibit No. 128.

18. On January 9, 2015, DEA filed an Issues Matrix, which represented input from all parties.

19. On January 20, 2015, the parties filed Initial Briefs.

ARGUMENT

I. DEA's Burden Of Proof To Show That The Proposed Rate Changes Are Just And Reasonable

20. DEA bears the burden of showing that its proposed rates are reasonable.[2] Minnesota law requires that every rate established by the Commission must be just and reasonable and that any doubt as to reasonableness must be resolved in favor of the consumer.[3]

[2] Minn. Stat. § 216B.16, subd. 4 (2014).
[3] Minn. Stat. § 216B.03 (2014).

21. The Minnesota Supreme Court found that the burden is on the utility to prove the facts required to sustain its burden by a fair preponderance of the evidence.[4] The Supreme Court described the Commission's role in determining just and reasonable rates in a rate proceeding:

> [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 acting 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]

22. To the extent that a regulated utility fails to show the reasonableness of its requests (*e.g.*, that its proposed expenses are not too high or its expected revenues are not too low) the Department recommends either rejection of such proposals or proposes adjustments to the utility's proposals so that the Association might realize some—rather than none—of its requests in a just and reasonable manner. To be clear, however, there is no duty of the Department (or any other non-utility party) to propose adjustments; it is equally appropriate for parties to simply recommend rejection if a utility fails to demonstrate that its proposals are just and reasonable. The Department in making recommendations does not, however, mean that the burden of proof has shifted to the Department.

II. ADOPTION OF THE SETTLEMENT BETWEEN DEA AND THE DEPARTMENT WILL RESULT IN REASONABLE AND JUST RATES

23. The Department and DEA reached an agreement on all issues in this matter. While DEA and the Department resolved certain issues through pre-filed testimony, DEA and the Department were able to resolve all disputed issues by the evidentiary hearing. DEA ultimately concurred with the Department's final recommendations that it presented in pre-filed testimony, which is memorialized in a Settlement Agreement. DEA Ex. 128 ("Settlement Agreement"). DEA and the Department agree that this resolution will result in reasonable and just rates for all DEA customers and recommend that the Commission approve DEA's Petition based upon the resolution of issues described in the Settlement Agreement.

24. The only disputed issues that remain in this matter after DEA and the Department entered into the Settlement Agreement were issues that the OAG-AUD raised.

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

25. The ALJ agrees with DEA and the Department that the Settlement Agreement will result in just and reasonable rates for DEA ratepayers. The ALJ recommends that the Commission approve the Settlement Agreement.

III. COST OF CAPITAL: RETURN ON EQUITY AND OVERALL RATE OF RETURN (UNDISPUTED ISSUE NO. 5)

A. The Department's Recommended Rate of Return is Reasonable

1. Summary of DOC's Recommended Rate of Return, Return on Equity, Cost of Debt, and Return on Total Capital

26. The Department initially recommended an overall rate of return of 4.75% as applied to total capitalization and 6.51% as applied to rate base. This rate is based on an initial recommended rate of return on common equity of 4.35%, a cost of debt of 5.31%, and overall return on total capital of 4.75%. The Department's recommendations were based on a total rate base of $171,613,635. If the Commission approves a rate base different than $171,613,635, then the return should be adjusted as follows:

Overall return on rate ("ROR") base = 4.75 x Total Capitalization/Approved Rate Base.[6]

27. The Department ultimately recommended a lower rate base of $171,181,006, which DEA accepted. Adjusting for a reduced rate base, the Department initially calculated a new overall rate of return of 6.53%. DEA agreed that the Department's rate of return calculations are reasonable.[7]

28. After the evidentiary hearing, the Department discovered a math error in the calculation of its recommended ROE of 4.35%. The methodology and formulas used by the Department were not affected by the math error. The Department's recommended ROE should have been 4.28%. Based upon this corrected figure, the Department would have initially recommended an overall rate of return of 4.71% as applied to total capitalization and 6.47% as applied to the rate base. DEA's cost of debt of 5.31% remains unchanged.[8]

29. Unless otherwise indicated, the following findings of fact reflect the Department's corrected calculations shown in DEA Proposed Ex. 128A and demonstrate that Department's rate of return calculations are reasonable.

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[6] DOC Ex. 300 at 19 (Amit Direct).
[7] DEA Ex. 126 at 4–5 (Larson Rebuttal); DOC Ex. at MAJ-S-6 (Johnson Surrebuttal); DEA Ex. 128 at 8–10 (Settlement Agreement).
[8] DEA Ex. 128A (Amendment to Settlement Agreement).

2. Overview of Cost of Common Equity

30. A fair rate of return is, by definition, the rate which, when multiplied by the rate base, will give a utility a fair return on its total investment. The sum of a utility's fair return, operating expenses, depreciation expenses and taxes equals the utility's total revenue requirement. In a competitive environment, prices (rates) and operating incomes (returns) are determined by the free interaction of market forces, such as supply and demand. These market forces ensure, under certain conditions, that an optimal level and mix of various goods and services are produced.[9]

31. In the regulated utility industry, the role normally assumed by competition is assumed by regulatory agencies that must ensure that utilities provide an appropriate supply of satisfactory services at reasonable rates. *Id.* To provide these services, the utility must be able to compete for necessary funds in the capital markets. *Id.* The Commission noted in its Order in DEA's prior rate case that:

> Dakota Electric differs from an investor-owned utility, in that, as a cooperative, all of its ratepayers are also the only investors in the utility. Rate of return, as applied to cooperatives, permits the development of sufficient margins to cover the cost of debt and equity capital.[10]

Thus, the Commission's role is to set a fair return that enables DEA to attract sufficient capital to provide reasonable service to its customers. The fair rate of return on equity is the cost of equity capital for the utility.[11]

32. The commonly used guidelines are the guidelines set forth in the *Bluefield* and *Hope* cases (*Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.* (*Bluefield*), 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas Co.* (*Hope*), 320 U.S. 591 (1944)):

- The rate of return should be sufficient to enable the regulated company to maintain its credit rating and financial integrity.

- The rate of return should be sufficient to enable the utility to attract capital.

- The rate of return should be commensurate with returns being earned on other investments having equivalent risks.

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[9] DOC Ex. 300 at 2 (Amit Direct).
[10] *In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-111/GR-09-175, Findings of Fact, Conclusions of Law, and Order at 10 (May 24, 2010).
[11] DOC Ex. 300 at 3 (Amit Direct).

33. The general concept of a fair rate of return on equity is the same for both co-ops and investor-owned utilities ("IOUs"). From a societal viewpoint, the cost of equity capital for DEA is the same as the cost of equity capital for any IOU with similar risk. Because co-ops are non-profit organizations, however, the required rate of return on equity for a co-op is different than its true cost of equity.[12]

34. The cost of equity capital for DEA is the rate of return that IOUs of similar risk to that of DEA must pay investors to induce them to invest in these utilities. To estimate this cost it is possible to use a market-oriented approach that relies on the concept of "opportunity costs." Investors are faced with many investment opportunities in the financial markets. To attract investors, an IOU must pay a return equal to the return that investors expect to earn on investments of comparable risk. This rate of return is the cost of equity capital to the IOU. When investors buy the common stock of a utility, they acquire the right to share in any dividends that the company may declare in the future. The prospect of these dividends serves as an inducement to investors.[13]

35. As far as a potential investor in common equity capital knowing what dividends a company will pay in the future, investors form certain expectations about future dividends, based on the company's past and current performance, the company's prospects for future growth, and investors' perceptions of the current and future economic environment.[14]

36. The expected dividend divided by the purchase price of the stock (the dividend yield) is a critical component of the cost of common equity capital. The investor in common stock expects to receive a flow of future dividends. To make the investment worthwhile, the price of the stock in the present period must be equal to the present value of all the expected future dividends discounted by the appropriate rate of return. If annual dividends grow at a constant rate over an infinite period, we can estimate the required rate of return on common equity capital in the following way:

> The expected (required) rate of return on equity = the current dividend yield + expected growth rate in dividends.

The formula is known as the Discounted Cash Flow ("DCF") method.[15]

37. Unlike any IOU, DEA has a unique feature: all of its ratepayers are required to invest in DEA and are also the only investors in DEA. The equity portion of the capitalization of DEA is properly termed "Patronage Capital," since it is collected from the utility's customers through rates. This is to say that a portion of every customer's electric bill is "earmarked" as capital credits and used to maintain a sound capital structure. These capital credits must be

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[12] DOC Ex. 300 at 3 (Amit Direct).
[13] *Id.* at 4.
[14] *Id.*
[15] *Id.* at 4–5.

returned to DEA's customers on a regular basis. Based on its historical experience, DEA determined that it needs to return $2,500,000 per year as capital credits.[16]

38. Because DEA is a co-op, it is a two-fold monopoly. First, like an IOU, it is the only provider of electric services in its service area. Second, every member of DEA must invest in DEA in order to receive any electric service. In contrast, any investors in an IOU make their decisions based on the merit of this investment relative to many other investment opportunities. As a result, the required rate of return on DEA's equity is not determined by the opportunity cost of investing capital somewhere else; rather, it is determined by the need to finance the growth of DEA's rate base and maintain a sound capital structure.[17]

39. Because DEA only purchases equity capital from its members and does not pay dividends out of its earnings, it is reasonable to expect that DEA's required rate of return on equity is lower than its true cost of equity capital.[18]

3. The Required Rate of Return on Equity for DEA

40. An adequate rate of return on equity capital (patronage capital) is a return that allows DEA to 1) achieve or maintain an appropriate debt coverage; 2) maintain an appropriate level of rate base growth; and 3) ensure consistent retirement of capital credits.[19]

41. To meet these financial requirements, the Department estimated a cost of equity for DEA of 4.28%.[20] Dr. Amit used a modified version of the formula generally used for estimating the cost of equity for an IOU in order to estimate the cost of equity for DEA, a co-op.[21] As Dr. Amit stated in this opening statement:

> [T]o determine its cost of common equity and overall rate of return, it is necessary to use different methods than the ones used to determine the cost of capital for [IOUs]. To attract investors, an IOU must pay returns equal to the returns that investors expect to earn on investments of comparable risk. To estimate such returns I commonly use market oriented methods such as Discounted Cash Flow or Capital Asset Pricing Models. However, because Dakota Electric is a cooperative, it is a two-fold monopoly. First, like an IOU, it is the only provider of electric service in its service territory. Second, every member of Dakota Electric must invest in DEA in order to receive any electric service. This capital investment is termed Patronage Capital. Thus, the electric bill for each member of Dakota Electric includes the member's equity

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[16] *Id.* at 5.
[17] *Id.* at 6.
[18] DOC Ex. 300 at 6 (Amit Direct).
[19] *Id.* at 6–7.
[20] DEA Ex. 128A at 2 (Amendment to Settlement Agreement).
[21] DOC Ex. 300 at 7, EA-2 (Amit Direct).

> contribution to the co-op and must be returned eventually to the co-op members as capital credits.[22]

Dr. Amit's modified formula is as follows:

> $K = g + [2{,}500{,}000/(ER \times TC_t)]$, where g is the annual growth rate in equity capital, ER is the test year equity ratio and TC_t is the test year total capitalization.[23]

Using this formula with a growth rate, g, of 2.45%, an equity ratio of 58.19%, and a test year total capitalization of $235,173,728, the Department recommended a rate of return on equity (K) of 4.28%.[24]

4. DEA Agrees that the Department's Proposed Rate of Return Is Reasonable

42. In its Rebuttal Testimony, DEA stated that it "agrees to the DOC overall rate of return calculations and input refinements." DEA's agreement was also reflected in the parties' Settlement Agreement.[25]

43. The ALJ agrees that the Department's proposed rate of return on equity, as corrected, is reasonable.

B. The Capital Structure, Cost of Debt, and the Cost of Capital for DEA

44. To arrive at the overall rate of return on total capital for DEA, Dr. Amit weighted the embedded cost of long-term debt and the rate of return on equity by the long-term debt ratio and equity ratio, respectively. To do so, Dr. Amit first needed to determine the appropriate capital structure. A well-accepted premise in financial literature is that an optimal capital structure, *i.e.*, one that minimizes the overall cost of capital, exists for any company. It is not easy to test whether a specific capital structure is optimal, however. The test is particularly difficult for an organization such as DEA, which cannot issue common equity stock in the financial markets, and is a not-for-profit company.[26]

45. One way to test for the reasonableness of the capital structure is to examine the value of Time Interest Earned Ratio, or TIER. TIER measures the ability to generate enough earnings to meet interest payments. TIER is calculated as net margins (net income) before interest expenses are deducted, divided by the interest expense. Both TIER and the equity ratio are important measures of DEA's financial strength. TIER is defined as the return on equity

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[22] DOC Ex. 312 (Amit Opening).
[23] DOC Ex. 300 at 9 (Amit Direct).
[24] *Id.* at 12; DEA Ex. 128A at 2 (Amendment to Settlement Agreement).
[25] DEA Ex. 126 at 4 (Larson Rebuttal); DEA Ex. 128 at 10, 128A (Settlement Agreement and Amendment).
[26] DOC Ex. 300 at 12 (Amit Direct).

capital plus interest expense divided by the interest expense. This relationship is expressed as follows:

$$T = [K \times ER + i \times (1\text{-}ER)]/[i \times (1\text{-}ER)],$$

Where:

T = TIER
K = rate of return on equity capital
ER = equity ratio
i = cost of long-term debt[27]

46. The above equation means that, given the rate of return on equity and the cost of long term debt, the level of TIER is determined by the equity ratio. Using DEA's cost of long-term debt (5.31) and the Department's proposed equity ratio (58.19%) combined the Department's cost of equity (4.28%), Dr. Amit calculated a TIER for DEA of 2.12.[28]

47. In determining whether a debt ratio of 41.81%, an equity ratio of 58.19%, and a TIER of 2.12 is financially satisfactory, the Department considered other market-oriented financial information.[29]

48. First, Dr. Amit determined that DEA's debt ratio of 41.81% reflects an "A" bond rating, which means that DEA has a "very strong capacity to meet financial commitments," which shows that DEA's financial position is strong.[30]

49. Second, the National Rural Utilities Cooperative Finance Corporation ("CFC"), which provides most of the long-term loans for DEA, requires a Modified Debt Service Coverage Ratio ("MDSC") of net operating income to annual debt service at no less than 1.35. Dr. Amit adjusted the Cooperative's calculations to reflect his proposed total debt of $98,336,368 and his estimated return on equity of 4.28%. These modifications result in only a minor change in the MDSC from 1.80 to 1.82.[31]

50. The following compares the Department's recommendation for DEA's capital structure, DEA's proposed capital structure and its capital structure as modified by the Department to DEA's proposed actual test year capital structure:[32]

Table 1: DEA's Proposed Capital Structure

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[27] *Id.* at 12–13.
[28] *Id.* at 13; DEA Ex. 128A at 2 (Amendment to Settlement Agreement).
[29] *Id.*
[30] *Id.* at 13–14. Because DEA operates as a not-for-profit company, the financial analysis as performed above would not be as applicable to a publicly traded electric utility company. *Id.* at 14.
[31] DOC Ex. 300 at 14 (Amit Direct).
[32] *Id.* at 15–16.

Component	$Amount	Capitalization
Equity	$136,837,360	59.60%
Debt	$92,752,617	40.40%
Total	$229,589,977	100.00%

51. DEA's capital structure, amended to reflect DEA's refinancing of long-term debt in January 2014, is:[33]

Table 2: DEA's Capital Structure
As Amended by the Department

Component	$Amount	Capitalization
Equity	$136,837,360	58.19%
Debt	$98,336,368	41.81%
Total	$235,173,728	100.00%

52. This capital structure is the appropriate capital structure to calculate the overall cost of capital for DEA. In general, for a publicly traded electric utility, a BBB rating is reasonable as it is considered an investment grade rating and is the most common Standard and Poor's ("S&P") rating for publicly traded electric utilities in the United States. DEA's debt and equity ratios under Dr. Amit's proposed capital structure meet the S&P requirements for an A rating. Moreover, DEA also meets the CFC's debt coverage requirement. Therefore, Dr. Amit concluded that DEA's proposed test-year capital structure as amended is appropriate. Dr. Amit's conclusions can be summarized by the following table:[34]

Table 3: DEA's Overall Cost of Capital

	Percentage of Total Capital	Cost Rate (%)	Weighted Cost (%)
Equity Ratio	58.19	4.28	2.49
Long-Term Debt	41.81	5.31	2.22
Total	100.00		4.71

[33] *Id.* at 16.
[34] *Id.*

53. Dr. Amit determined that he needed to make an adjustment to DEA's 4.71% overall return on total capital. As noted above, because DEA purchases equity capital only from its members, who are required to invest in DEA in order to receive any electric service, the overall cost of capital for DEA does not recognize the difference between DEA's total capitalization and DEA's rate base. Thus, to allow both bondholders and equity holders (DEA members) to recover their investment costs, the return on total capital must be adjusted to recognize any difference between the rate base and total capitalization. After making this adjustment, Dr. Amit calculated an overall rate of return on rate base for DEA of 6.47%.[35]

54. As applied to total capitalization, the Department recommended an overall rate of return of 4.71%; however, as applied to the rate base, the Department recommended an overall rate of return of 6.47%. This rate is based on Dr. Amit's recommended rate of return on common equity of 4.28%, a cost of debt of 5.31%, and overall return on total capital of 4.71%. If the Commission approves a rate base different than $171,613,635, then the return should be adjusted as follows:

Overall return on rate (ROR) base = 4.71 x Total Capitalization/Approved Rate Base.[36]

55. The Department ultimately recommended a lower rate base of $171,181,006, which DEA accepted. Adjusting for a reduced rate base, the Department calculated a new overall rate of return of 6.47%. DEA agreed that the Department's rate of return calculations are reasonable. DEA's agreement with the Department analysis and conclusions is also reflected in the parties' Settlement Agreement.[37]

56. The ALJ agrees and also finds that all of the Department's rate of return calculations, as agreed to by DEA, are reasonable.

IV. 2014 TEST YEAR ADJUSTMENTS TO DEA'S PROPOSED RATE BASE AND INCOME STATEMENT

57. All financial issues have been resolved between DEA and the Department, and between the OAG-AUD and the Department.

A. DEA's Business Operations and Rate Case Test Year

58. DEA is a non-profit, member-owned distribution electric utility located in Farmington, which serves more than 103,000 members in Dakota, Scott, Rice, and Goodhue counties. DEA's operations consist of both regulated and non-regulated activities. In addition, DEA has a for-profit wholly-owned subsidiary holding company, Midwest Energy Services ("MES"). MES in turn owns Energy Alternatives Parent, Inc. ("EAI"), which owns Energy Alternatives Solar, LLC ("EAS"). DEA's non-regulated operations included sub-contracting

[35] *Id.* at 17, 19, EA-2; DEA Ex. 128A at 2 (Amendment to Settlement Agreement).
[36] *Id.* at 19; DEA Ex. 128A at 2 (Amendment to Settlement Agreement).
[37] DEA Ex. 126 at 4–5 (Larson Rebuttal); DOC Ex. at MAJ-S-6 (Johnson Surrebuttal); DEA Ex. 128, 128A (Settlement Agreement and Amendment).

services to other utilities and equipment sales to customers. According to DEA, its non-regulated operations were tracked in detail, using separate project codes, and were mapped to FERC Accounts 415 and 416 and reflected on Form 7, Line 25, Non-Operating Margins.[38]

59. Since its last rate case in 2009, DEA phased out a large portion of its for-profit subsidiary activities. In 2011, MES sold all of its shares of stock in Consulting Engineers Group, Inc. In 2012, EAI sold all of its membership interests in its leasing and wholesale generation business. Thus, the only significant subsidiary business activity appears to be related to EAS, which leases customer-sited solar photovoltaic generation. DEA's subsidiaries' books are kept separately from DEA's books. The net income or loss related to DEA's consolidated subsidiaries is reflected on Form 7, Line 24, Income (Loss) from Equity Investments.[39]

60. To determine its revenue deficiency and need for increased electric rates, the Cooperative used an historical test year, representing the twelve months ending December 31, 2013, adjusted for known and measurable changes. To develop its test-year rate base, DEA used its December 31, 2013 balances found on the National Rural Utilities Cooperative Finance Corporation Financial and Statistical Report (Form 7) to determine the test-year amount for plant balances and consumer deposits. To develop its test-year operating expenses, DEA began with its actual 2013 expenses and added several adjustments to determine the test-year amounts.[40]

B. Other Non-Operating Income (Undisputed Issue No. 1)

61. In its proposed test year, DEA included an adjustment for other non-operating income when calculating its test-year revenue deficiency. As shown in DEA's revenue requirements summary, DEA reduced its required net operating income and resulting test-year revenue deficiency by $399,147 for "other non-operating income." The Department asked DEA in DOC IR No. 119 what the $399,147 in other non-operating income consisted of, why it was used to reduce the test-year revenue deficiency, and what DEA's other non-operating income was in prior years.[41]

62. DEA's response to the IR indicated that $272,889 of net income from DEA's subsidiary was included in DEA's calculation of its required net operating income and test-year revenue deficiency shown on the revenue requirement summary. The Department was concerned with DEA's proposed treatment of its wholly-owned for-profit subsidiary's net income because normally, rate-regulated utilities calculate their required net operating income and resulting test-year revenue deficiency on a stand-alone basis, meaning that costs and revenues are allocated appropriately between the utility and non-utility businesses, so that only the utility's financial information is used to set rates. This approach prevents a utility's non-regulated subsidiary activities from impacting the rates charged to ratepayers.[42]

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[38] DOC Ex. 308 at 5 (Johnson Direct) (citing DEA Ex. 101 at 1 (Larson Direct); DEA Ex. 121 at 1 (DEA Workpaper 7)).
[39] *Id.* at 5–6 (citing DEA Ex. 121 at 1 (DEA Workpaper 7)).
[40] *Id.* at 2, 4 (citing DEA Ex. 101 at DEA-1, at 1 of 20, DEA-2, at 2 of 8 (Larson Direct)).
[41] *Id.* at 6 (citing DEA Ex. 103 at DEA-2, at 1 of 8, Lines 5 and 12 (Larson Direct)).
[42] *Id.* at 6–7.

63. Mr. Johnson explained that an inclusion of the subsidiary's net income in the other non-operating income would have decreased the overall revenue deficiency and resulted in lower rates for ratepayers. However, the opposite would have occurred if DEA had selected 2012 as the test year. That is, if DEA had filed a rate case with a 2012 test year, it would have included $521,609 of its subsidiary's net losses in its overall revenue deficiency, which would have resulted in higher rates for ratepayers.[43]

64. Based on his analysis, Mr. Johnson concluded that the $272,889 of net income from DEA's subsidiary should be removed from DEA's calculation of its required net operating income and test-year revenue deficiency shown on the revenue requirement summary.[44]

65. DEA agreed with the Department's recommended adjustment. The OAG-AUD initially raised questions as to use of non-regulated subsidiary net income when calculating non-operating income, but at the evidentiary hearing, confirmed that the questions were addressed and OAG-AUD had no concerns regarding DEA's non-operating income of $399,147 being reduced as recommended by the Department.[45]

66. The ALJ agrees that the Department's recommended adjustment regarding removing $272,889 of net income from DEA's subsidiary from DEA's calculation of its required net operating income and test-year revenue deficiency is reasonable.

C. Accumulated Depreciation Expense (Undisputed Issue No. 2)

67. DEA proposed a test-year adjustment to normalize its December 2013 depreciation expense for the test year. DEA's proposed adjustment increased test-year depreciation expense by $78,749. The Department had concerns with DEA's proposed adjustment because DEA did not record this additional depreciation expense to its test-year accumulated depreciation balances. Normally, all depreciation expense is recorded on the income statement with an offsetting entry to accumulated depreciation. As a result, the Department recommended that DEA's test-year accumulated depreciation balance be increased by $78,749.[46]

68. DEA acknowledged its omission in recording the additional depreciation expense to its test-year accumulated depreciation balances and agreed with the Department's recommended adjustment. The OAG-AUD initially recommended an increase of $39,375 to accumulated depreciation, but at the evidentiary hearing confirmed that, because Dakota

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[43] *Id.* at 7–8.
[44] DOC Ex. 308 at 7–9 (Johnson Direct); DOC Ex. 310 at 10 and MAJ-S-1, Line 4 (Johnson Surrebuttal).
[45] DEA Ex. 126 at 5 (Larson Rebuttal); DEA Ex. 128 (Settlement Agreement of DOC and DEA); OAG-AUD Ex. 204 at 3-8 (Lee Rebuttal); Tr. Vol. 1 at 114 (Lee).
[46] DOC Ex. 308 at 9 (Johnson Direct) (citing DEA Ex. 102 at DEA-1, at 8 of 20 (Larson Direct)).

Electric's test year was based on year-end balances, the test-year accumulated depreciation should have been increased by $78,749 as the Department had recommended.[47]

69. The ALJ agrees that the Department's adjustment to test-year depreciation expense by $78,749 is reasonable.

D. Capitalized Payroll Expense (Undisputed Issue No. 3)

70. DEA proposed a test-year adjustment to normalize the percentage of payroll that is expensed (as opposed to capitalized) in the test-year. As shown in DEA's calculations, the average percentage of payroll expensed from 2009 to 2012 was 88.1%. However, DEA only expensed 86.8% of its payroll in 2013. As a result, DEA proposed to increase the portion of test-year payroll that was expensed on the income statement by 1.3% or $228,590.[48]

71. The Department was concerned with DEA's proposed adjustment because it did not reduce the test-year portion of payroll that was capitalized in rate base, which would result in DEA having 13.2% of its 2013 payroll capitalized in rate base, and a recovery of a total of 101.3% of its 2013 payroll in the test year (consisting of 88.1% on the income statement and 13.2% in rate base). Mr. Johnson explained that, while the Department did not oppose the increase in payroll expense, it did recommend that DEA record an offsetting entry to rate base for the portion of test-year payroll that was normalized and expensed on the income statement, which resulted in DEA's test-year rate base being reduced by $228,590.[49]

72. DEA acknowledged in its Response to DOC IR No. 117 that it did not reduce the test-year portion of payroll that was capitalized in rate base. DEA agreed with the Department's recommended adjustment to rate base for the payroll expense adjustment.[50]

73. The ALJ agrees that the Department's recommended adjustment to rate base for the payroll expense adjustment is reasonable.

E. Cash Working Capital (Undisputed Issue No. 4)

74. Cash working capital is the amount of liquidity needed on hand to pay for the costs DEA incurs to serve its members; cash working capital is needed because DEA incurs costs before ratepayers pay bills. DEA included cash working capital in its test-year rate base and

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[47] *Id.* at MAJ-8 (Johnson Direct); DEA Ex. 126 at 5 (Larson Rebuttal); DEA Ex. 128 (Settlement Agreement); OAG-AUD Ex. 203 at 8, 9 (Lee Direct); Tr. Vol. 1 at 116 (Lee).
[48] DOC Ex. 308 at 9 (Johnson Direct) (citing DEA Ex. 102 at DEA-1, at 4 of 20 (Larson Direct)).
[49] *Id.* at 9–10.
[50] *Id.* at MAJ-9 (Johnson Direct); DEA Ex. 126 at 5 (Larson Rebuttal); DEA Ex. 128 (Settlement Agreement of DOC and DEA).

applied lead/lag study factors to its test-year cash operating expenses to determine its cash working capital requirement of $6,987,282, which DEA then added to its test-year rate base.[51]

75. The Department was concerned with DEA's cash working capital calculations because DEA included test-year interest expense of $5,317,533 in its cash working capital calculations (shown in DEA Ex. 110 at DEA-9, at 1 of 1 (Larson Direct)) even though, for ratemaking purposes, interest expense or the cost of debt is to be included in the overall rate of return, not in cash working capital calculations.[52]

76. Mr. Johnson recommended that interest expense be excluded from test-year cash working capital. In addition, he recommend that DOC's various other adjustments to test-year operating expenses (including the removal of interest expense) be reflected in cash working capital. The effect of these recommendations on test-year cash working capital reduced test-year cash working capital by $125,290 for the lead/lag study. DEA agreed with the Department's recommended adjustment to cash working capital.[53]

77. Mr. Johnson further explained that it was necessary to adjust the rate of return on rate base as a result of the discussion in Dr. Amit's testimony and the adjustments Mr. Johnson recommended to DEA's rate base. This calculation was as follows: [54]

Overall return on rate (ROR) base = 4.75 x Total Capitalization/Approved Rate Base

*6.47 = 4.71 * ($235,173,728)/($171,613,635 – $432,629)*[55]

F. Revenue Requirements Summary for Dakota Electric Association

78. Dakota Electric initially proposed a revenue increase of about $4,189,000 or 2.1% based on a comparison of proposed test year total revenue requirements and total revenue.[56]

79. The Department's "Revenue Requirements Summary for Dakota Electric Association," DOC Ex. 110 at MAJ-S-1 (Johnson Surrebuttal), summarized the Department's recommendations for DEA's revenue requirements. Column (a), line 7, is DEA's calculated revenue deficiency of $4,189,232 under present rates for the test-year ended December 31, 2013.

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[51] *Id.* at 10–11 (Johnson Direct) (citing DEA Ex. 110 at DEA-9, at 1 (Larson Direct); DEA Ex. 103 at DEA-2, at 2 of 8 (Larson Direct)).
[52] *Id.*
[53] *Id.* at 11, MAJ-4; DEA Ex. 126 at 5 (Larson Rebuttal); DEA Ex. 128 (Settlement Agreement of DOC and DEA).
[54] The adjustment to DEA's rate proposal including adjustments based on DOC Witness, Dr. Eilon Amit's recommendations for DEA's cost of capital, are reflected in DOC Ex. 110 at MAJ-S-6 (Johnson Surrebuttal) (as amended by Proposed DEA Ex. 128A at 2 (Amendment to Settlement Agreement)).
[55] DOC Ex. 308 at 12 (Johnson Direct); DOC Ex. 310 at 11 and MAJ-4 (Johnson Surrebuttal); DEA Ex. 128A at 2 (Amendment to Settlement Agreement).
[56] DEA Ex. 101 at 6 (Larson Direct).

Column (b), line 7, was the DOC's calculated revenue deficiency of $4,358,994, which was based on the Department adjustments with an overall rate of return of 6.47% as shown in DOC Ex. 110 at MAJ-S-6 (Johnson Surrebuttal).[57]

80. The final revenue deficiency determined by the Commission must be consistent with Minn. Stat. § 216B.16, subd. 5, which does not allow the revenue requirement to exceed the level of rate increase requested by the public utility. Thus, since the total revenue requirement that the Department recommended for DEA exceeded DEA's requested increase in rates, the Department concluded that DEA supported its proposed overall rate increase. DEA agreed with the Department's recommendations, as is reflected in the Settlement Agreement between DEA and the DOC.[58]

81. Consistent with the Department's recommendations, the ALJ finds that DEA's proposed revenue increase is reasonable.

G. Sales Forecast and Test Year Wholesale Power Costs. (Undisputed Issue No. 6)

82. Reasonable sales forecasts are an essential part of the rate-making process: test-year sales volumes are important factors in calculating a utility's revenue requirement because sales levels affect revenues and expenses. In general, lower sales levels produce higher rates, because costs are spread over fewer units. Because sales levels are an integral input in calculating a utility's rates, the method of determining the sales levels must be reasonable. Test-year sales volumes are also essential to a class cost of service study ("CCOSS") and rate design. In designing rates, test-year sales volumes are used to allocate costs in the CCOSS, which is then used as a benchmark comparison to establish the apportionment of revenue responsibilities to customer classes. Moreover, when establishing final rates, the test-year sales volumes are used to determine the overall revenue requirements and the individual tariff rates.[59]

83. Based on his independent review and analysis, Department witness Michael Zajicek generally supported DEA's estimates of sales volumes and customer counts. He recommend that the weather-normalized sales volumes that resulted from DEA's forecasts be used for the residential customer class and that the test-year sales volumes that resulted from DEA's calculations be used for the remaining rate classes: the small general service rates classes (Rate 41), the general service (Rate 46), full and partial interruptible service (Rates 70 and 71) and the other rate classes.[60]

84. DEA's forecast methodology began with an estimate of weather-normalized test-year energy sales for the Residential and Farm service rate class (Rate 31), based on a regression analysis using thirteen years of monthly use per customer ("UPC") sales against weather data.

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[57] DOC Ex. 110 at MAJ-S-1 (Johnson Surrebuttal); DEA Ex. 128A at 2 (Amendment to Settlement Agreement).
[58] *Id.* at 12–13; DEA Ex. 128 (Settlement Agreement).
[59] DOC Ex. 306 at 2 (Zajicek Direct).
[60] *Id.* (citing DEA Ex. 101 at DEA-1, at 12 of 20 through 19 of 20 (Larson Direct)).

DEA then averaged the most recent five years of UPC sales and multiplied the resulting annual test-year weather-normalized UPC amount by the 2013 budgeted test-year numbers of customers. For the Small General Service rate class (Rate 41), the General Service rate class (Rate 46) and for the Interruptible Service Partial rate class (Rate 71), DEA estimated test-year energy sales based on five years of actual average monthly sales multiplied by the 2013 budgeted numbers of customers data rather than use a regression analysis. For the Interruptible Service Full rate class (Rate 70), DEA estimated test-year energy sales based on three years of actual average monthly sales multiplied by the 2013 budgeted numbers of customers data rather than use a regression analysis.[61]

85. To develop its sales forecast for the Residential and Farm service rate class, DEA used monthly historical energy and customer count data from January, 2001 through December, 2013. To estimate sales for all other rate classes the Cooperative used historical energy and customer count data for the last five years, from January, 2009 through December, 2013, with one exception. For the Interruptible Service Full rate class (Rate 70) energy sales and customer counts were based on a three-year average, from January, 2011 through December, 2013. DEA stated that it used a three-year average for this class due to an addition of several meters at the Minnesota Zoo in 2010, without a corresponding increase in kWh usage.[62]

86. DEA's proposed energy and customer count data were based on DEA's monthly financial reports. The weather variables (Heating Degree days ("HDD") and Cooling Degree days ("CDD")) used in the regression model were obtained from the Midwestern Regional Climate Center ("MRCC"). Normal weather variables data were based on the period of 1871 to 2013 according to DEA's Response to DOC IR No. 501.[63]

87. Based on his analysis, Mr. Zajicek concluded that DEA's data preparation in relation to its use in forecasting was reasonable, and use of the Cooperative's financial reports was reasonable because they provide accurate information regarding energy usage and customer counts for DEA. Mr. Zajicek was able to replicate DEA's regression models and obtained similar results for the Residential and Farm Service rate class. He concluded that DEA's statistical model and the results of the model were statistically reasonable and concluded that the regression model used to forecast energy sales in this rate case was statistically reasonable. He recommended that the Commission use the energy sales volume and budgeted customer count shown in the Cooperative's Direct Testimony of Doug Larson, DEA Ex. 101 at DEA-1, at 12 of 20 through 19 of 20 (Larson Direct).[64]

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[61] *Id.* at 3–4 (citing DEA Ex. 101 at 11, lines 2-8 (Larson Direct); DEA Ex. 122 at Workpaper 13, at 1 of 12). Further information about the interruptible sales class is set out in Mr. Larson's Direct Testimony. DEA Ex. 101 at Workpaper 13, at 1 of 12. Further information about other rate classes is set out in the Cooperative's Response to DOC IR No. 507, which is DOC Ex. 306 at MNZ-1 (Zajicek Direct). DOC Ex. 306 at 5 (Zajicek Direct).

[62] *Id.* at MNZ-1.

[63] *Id.* at MNZ-2.

[64] DOC Ex. 306 at 6–8 (Zajicek Direct); DOC Ex. 313 (Zajicek Opening Statement). Mr. Zajicek also reviewed the Cooperative's filings regarding test year wholesale power costs and

(Footnote Continued on Next Page)

88. The ALJ agrees that the Department's recommendations regarding test-year sales forecasts and wholesale power costs are reasonable.

V. CLASS COST OF SERVICE STUDY (UNDISPUTED ISSUE NO. 7; DISPUTED ISSUE NO. 4)

A. CCOSS Background

89. A Class Cost of Service Study ("CCOSS") is designed to identify the cost responsibility, as accurately as possible, of each customer class for each cost incurred by the utility in providing service. A CCOSS is conducted to determine cost causality to the utility, and assigns costs to the customer groups who impose them upon the system. Through this process, costs are equitably allocated among all customer classes in a manner that best represents the true nature of the factors that caused the costs to be incurred (cost causation).[65]

90. According to the 1992 *Electric Utility Cost Allocation Manual of the National Association of Regulatory Utility Commissioners* ("NARUC Electric Manual"), a CCOSS is comprised of three main steps:

1. *Functionalization* – Assigning revenue requirements to specified utility functions, based on their purpose.

2. *Classification* – Refining functionalization to identify the utility operation on which the functionalized dollars are spent.

3. *Allocation* – Assigning functionalized and classified costs to customer classes, consistent with the cost impact each class imposes on the system.[66]

91. Costs are typically functionalized by the Uniform System of Accounts as provided by the Federal Energy Regulatory Commission ("FERC"). These accounts group costs into their various functions, such as production (*e.g.* costs associated with power generation and wholesale purchases), transmission (*e.g.* assets and expenses associated with the high voltages system) and distribution (*e.g.* meters).[67]

(Footnote Continued from Previous Page)
participated in a meeting of all parties and Commission Staff to address discrepancies in test year wholesale power costs. The Surrebuttal testimony of Mr. Douglas Larson addressed several errors in billing units and other errors in a spreadsheet the Department provided to Dakota to respond to DOC IR No. 505; these corrections greatly reduced the discrepancy; and Mr. Zajicek concluded that the remaining discrepancy was neither material nor appropriate for a financial adjustment. DOC Ex. 313 (Zajicek Opening Statement).

[65] DOC Ex. 301 at 3 (Ruzycki Direct).

[66] *Id.* at 4.

[67] *Id.*

92. Classification further separates the functionalized costs based on the primary driver of those costs, and divides costs based on the factors to which they are most sensitive. Functionalized costs are classified as customer, demand, or energy costs according to how the costs are incurred:

- *Customer Costs* – Operating and capital costs that are a function of the number of customers on the system regardless of the customers' energy consumption (*e.g.* metering, billing, tracking accounts, and responding to customers' questions). Often allocated among the customer classes based on the number of customers in the respective classes, typically weighted to reflect, for example, differences in the metering costs among classes.

- *Demand Costs* – Costs incurred to serve the peak demand on the system (*e.g.* the size of the distribution system). Often allocated among the customer classes based on the energy which the system must supply to serve the various customer classes. Peak responsibility and demand factors are often used to allocate costs related to transmission, distribution, and generation.

- *Energy Costs* – Costs that vary with the quantity of energy produced (*e.g.* cost of fuel). Often allocated among the customer classes based on the energy which the system must supply to serve the various customer classes.[68]

B. DEA's Embedded CCOSS Is Reasonable

93. After evaluation of the Association's proposed CCOSS, the Department concluded that DEA's proposed CCOSS is reasonable. DEA used the same methodology that the Commission approved in DEA's last rate case with the exception of two changes outlined below. DEA's classification and allocation of the functionalized accounts are generally consistent with the NARUC Manual, and Dakota Electric has made relevant updates to its input data in calculating the CCOSS. In addition, DEA used reasonably current data in its CCOSS.[69]

94. The ALJ agrees that DEA's proposed CCOSS is reasonable.

95. Dakota Electric made two changes to its CCOSS for this case. First, DEA implemented a minimum-size methodology to classify specific distribution accounts. The Commission required DEA to complete a minimum-system study by using the minimum-size method:

> Dakota Electric shall, in its next rate case, either use the minimum–size method to classify Distribution accounts, or provide

[68] *Id.* at 5-6.
[69] *Id.* at 13–14.

> such an analysis to support the outcome of the zero-intercept method.[70]

Second, DEA allocated new ancillary service energy costs to customer classes based on kWh purchases and the ancillary services rate. The Department agreed that both modifications are reasonable.[71]

1. DEA's Minimum-Size Method for Classifying Distribution Plant Accounts Is Reasonable

96. As indicated above, DEA used the minimum-size method to classify distribution plant accounts in this case. DOC Ex. 301 at 7 (Ruzycki Direct). Historically, DEA used the zero-intercept method to classify distribution plant accounts. *Id.* The Association stated the following:

> The minimum-size system is one of two common methods used to classify certain distribution plant accounts between "consumer" and "demand." Dakota Electric was ordered to use the minimum-size method in future rate cases, or provide a justification as to why the Cooperative should continue to use the zero-intercept method. The analysis of the minimum-size method is contained in Workpaper 21. This workpaper fully describes the development of this analysis.[72]

Moreover, DEA stated in Workpaper 21:

> Since being rate-regulated by the Minnesota Public Utilities Commission . . . in 1981, every general rate case filed by Dakota Electric Association has used the Zero-Intercept Method to classify distribution plant into customer and demand components.

Dakota showed that the minimum system study in this rate case—which estimated a 61.5% weighted customer component of the distribution system in Accounts 364, 365, 367, and 368 of the FERC—is only 4.4 percentage points higher than the 57.1% weighted customer component from the previous rate case in which a zero-intercept methodology was used.[73]

97. In the NARUC Electric Manual, the minimum-size method determines the minimum size for each piece of equipment currently installed by the utility to serve the minimum

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[70] DOC Ex. 301 at 6 (Ruzycki Direct); *In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-111/GR-09-175, Findings of Fact, Conclusions of Law, and Order at 23 (May 24, 2010).
[71] DOC Ex. 301 at 11–12 (Ruzycki Direct).
[72] *Id.* at ZR-2 at 2; DEA Ex. 125 at Workpaper 21 (Larson Direct).
[73] *Id.* at ZR-2 at 2; DOC Ex. 302 at 4 (Ruzycki Rebuttal); DEA Ex. 125 at Workpaper 21 (Larson Direct).

loading requirement of customers. Theoretically, this method assumes that a least-size distribution system can be built to the size necessary to offer customers the option of taking service. For example, in this method of distribution cost classification, the average installed book cost of the minimum size pole that is currently installed by the Cooperative is determined, and all the poles across the system are priced according to the minimum size unit cost. This minimum system cost is then classified as customer-related and allocated according to the number of customers per rate-class. Costs beyond those classified as customer-related in this method, and that are not directly assigned to customers (*e.g.* meters) are classified as demand related.[74]

98. By contrast, the zero-intercept method is based on an estimated linear relationship between the cost of distribution equipment and the size of the equipment. For example, given a conductor of a certain size, it is assumed that as the current carrying capability of the conductor increases, the cost increases commensurately. An equation is created to establish the linear relationship such as the one below:

$$y=a+bx$$

y represents the per-unit cost of the equipment
x represents the size or capacity of the equipment
where ***a and b*** represent the intercept and the slope of the line, respectively.

Using the system equipment and cost data, the theoretical minimum size (***x***) can be set to zero, and the intercept (***a***) will estimate the cost of the equipment that is invariant to the size of equipment installed. The cost of the equipment at zero size is considered the customer component, and the remainder of the cost is classified as demand-related.[75]

99. Differences in classification of customer and demand-related costs can be expected from the two different methods. Further, choices in the parameters of both methods can result in different cost classifications not only between methods, but also within methods.[76]

100. For minimum-size studies, the analyst chooses which equipment will be the minimum equipment to determine the customer-related charges; choices include the historical minimum sized equipment installed across the system, the current minimum sized equipment installed on the system, or the minimum requirements to meet safety standards.[77]

101. Because the zero-intercept methodology is based on statistical linear regression, the selection and use of data is very important. Even a well-thought-out model may produce statistically unreliable or nonsensical results such as a negative intercept due to incorrect data or some other data abnormality that would need to be corrected if possible. The results of a zero-

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[74] DOC Ex. 301 at 8 (Ruzycki Direct); DOC Ex. 302 at 4 (Ruzycki Rebuttal).
[75] DOC Ex. 301 at 9 (Ruzycki Direct).
[76] *Id.*
[77] *Id.* at 10.

intercept methodology can be susceptible to manipulation due to the selection and incorporation or deletion of data in constructing the model. Nevertheless, the NARUC Electric Manual states: "In most instances, [the zero-intercept methodology] is more accurate, although the differences may be relatively small." Therefore, the NARUC Electric Manual concludes that the two methods should produce similar results.[78]

102. DEA chose the following equipment for its minimum-size study: equipment in Account 364 (Poles, Towers, and Fixtures), Account 365 (Overhead Conductors and Devices), Account 367 (Underground Conductors and Devices), and Account 368 (Line Transformers) as follows, based on the minimum sizes on DEA's system:

- Poles, Towers, and Fixtures – a 35 foot Class 5 pole;
- Overhead Conductors and Devices – a #4 ACSR (Aluminum Conductor Steel-Reinforced) overhead conductor;
- Underground Conductors and Devices – a #2 URD (Underground Residential Distribution wire) underground conductor;
- Line Transformers – a 10 kVa single phase overhead transformer.

The Department confirmed that the Cooperative chose the smallest size equipment in service that would be necessary to serve customer load.[79]

103. The Department concluded that DEA's assumptions regarding the minimum-size equipment selected for the analysis are reasonable because they are grounded in reality and reflect real-world minimum-size equipment needed to allow customers to receive service.[80] The ALJ agrees with the Department's conclusions.

2. OAG-AUD's Proposed Zero-Intercept Proxy for Classification of Distribution Plant Accounts Is Not Reasonable

104. OAG-AUD witness Mr. Nelson recommended, due to perceived inadequacies in both the minimum-size and zero-intercept methodologies as presented in the NARUC Electric Manual, and widely used for CCOSS analyses, that the Commission adopt his methodology, rather than DEA's, to determine the customer- and demand-related costs in the CCOSS for distribution plant accounts.[81]

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[78] *Id.*; DOC Ex. 311 at 92 (NARUC Electric Manual).
[79] DOC Ex. 301 at 10–11 (Ruzycki Direct).
[80] *Id.* at 11.
[81] DOC Ex. 302 at 1 (Ruzycki Rebuttal).

a. There Is More Than One Reasonable Way to Conduct a Minimum-System Study

105. The overall goal of a minimum-system study is to allocate distribution system costs between the costs of delivering power to customers (customer costs) and the costs of ensuring that the distribution system is large enough to provide reliable service during peak periods (capacity costs). If it were possible for customers to drive to a DEA service station to buy energy, as consumers do when they buy gasoline for vehicles, then each customer would be responsible for the costs of obtaining that energy. Since electricity is delivered to each customer's location via a system that has been built to deliver power, it is necessary to separate out these costs as they are part of the customer costs.[82]

106. Mr. Nelson infers that there is only one way to conduct a minimum-system analysis, which is inaccurate. If only one prescriptive and correct way existed to determine how to split customer and demand costs in the minimum system analysis, there would be no debate regarding classification of these costs. Instead, a CCOSS is designed to identify the cost responsibility, *as accurately as possible*, for each customer class of each cost incurred by the utility in providing service to that customer class. Thus, the CCOSS provides a guideline for rate design.[83]

107. Moreover, a CCOSS involves considerable judgment, such as potential allocations of these costs, given the circumstances for each utility. Overall, it is important for a CCOSS to be based on methods that are transparent, fair to all classes, fact-based and readily understandable.[84]

108. Thus, the zero-intercept method is not "the" method or the "theoretically correct" way to classify distribution plant accounts. The Department agreed that the zero-intercept model is an appropriate method, but did not agree that it is the only appropriate method. Moreover, while the Department agreed with Mr. Nelson that, in a perfect world, with perfect data availability, the zero-intercept methodology would more closely approximate a theoretical zero-sized system than a minimum size methodology, there is not perfect data availability. As a result, the minimum-size method is widely used in CCOSSs. In this proceeding, two methods produced similar results: approximately 60% of the costs are customer related. DEA's minimum-size study used real costs from DEA's actual system to estimate the costs to build a minimum system necessary to allow customers to take service.[85]

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[82] DOC Ex. 303 at 5 (Ruzycki Surrebuttal); DOC Ex. 302 at 6 (Ruzycki Rebuttal).
[83] *Id.* at 2–3; DOC Ex. 301 at 3 (Ruzycki Direct).
[84] DOC Ex. 302 at 3 (Ruzycki Rebuttal).
[85] *Id.* at 4–5.

b. The OAG-AUD's Zero-Intercept Proxy Does Not Reasonably Classify Distribution Plant Costs Because It Substantially Under Classifies Customer Costs

109. In his direct testimony, OAG-AUD witness Mr. Nelson proposed an alternative method for classifying distribution plant costs in a CCOSS, which he called the "zero-intercept proxy." Mr. Nelson stated the following:

> I developed a proxy for the zero-intercept method that does not necessitate the use of regression analysis and requires readily available data.
> . . .
> The proxy is based on the theory laid forth by the NARUC Electric Manual except I use known information as opposed to running a regression to estimate the zero-intercept. Specifically, the proxy is calculated by subtracting the material unit cost of the smallest size distribution equipment used for DEA's minimum size method from the installed unit cost of the same sized distribution equipment.

Mr. Nelson stated that "subtracting the material cost from the installed cost is equivalent to obtaining the zero-intercept estimation." The OAG-AUD's zero-intercept proxy classifies 38.3% of distribution plant as customer costs. Mr. Nelson testified that the "majority of the reason" for why the OAG-AUD's 38.3% is substantially lower than DEA's own zero-intercept calculation (57.1%) is that all material costs are taken out from DEA' s distribution system.[86]

110. Thus the OAG-AUD's method does not reasonably reflect all of the costs of a system that is capable of delivering power to customers, so it does not meet the basic requirement of this allocation. As a result, the Department concluded that the proposed proxy zero-intercept is not a reasonable method to separate all of the estimated costs of being capable of delivering power from the estimated costs of providing reliable service. The OAG-AUD's method considers only the costs of installing a minimum size pole, but does not include the equipment costs even of the smallest size pole that would need to be installed, let alone other equipment needed to deliver power to DEA's customers. The OAG-AUD's method is also at odds with the NARUC Electric Manual, which clearly directs an analyst to consider minimum material costs when conducting a zero-intercept study.[87]

111. DEA's minimum-size method is consistent with the NARUC Electric Manual and with the Commission's Order in DEA's 2009 rate case (Docket No. E111/GR-09-175).[88]

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[86] OAG-AUD Ex. 200 at 20, 24 (Nelson Direct); Tr. Vol. 1 at 90 (Nelson).
[87] DOC Ex. 302 at 6 (Ruzycki Rebuttal); Tr. Vol. 1 at 96, 99–100 (Nelson); DOC Ex. 311 at 92–93 (NARUC Electric Manual).
[88] DOC Ex. 303 at 3, 5 (Ruzycki Surrebuttal); DOC Ex. 311 at 95 (NARUC Electric Manual).

C. Summary of the Department's CCOSS Recommendations

112. Based on all of the information available to date in the record, the ALJ recommends that the Commission adopt Dakota Electric's proposed CCOSS. In particular, DEA's minimum-size method for classifying distribution plant accounts is reasonably accurate, grounded in reality and reflects real-world minimum-size equipment needed to serve customer load on DEA's system.[89] The ALJ recommends that the Commission accept DEA's proposed CCOSS as a guideline for rate design.

VI. RATE DESIGN (UNDISPUTED ISSUE NO. 8, DISPUTED ISSUE NO. 6)

A. Rate Design Background

113. Without competition, government regulation approximates the results that would be achieved in a competitive environment. Rate design is the second step of the two-step rate making process. In the first step, the Commission determines the revenue requirement, which is quasi-judicial and fact intensive. The second step, designing rates to charge customers, is largely a quasi-legislative function. While the second step of rate making largely involves facts, it also involves policy decisions.[90]

B. Rate Design Goals

114. The Commission has relied on the following principles in designing reasonable and just rates:

1. Rates should be designed to allow the Association a reasonable opportunity to recover its revenue requirement, including the cost of capital;
2. Rates should promote efficient use of resources by sending appropriate price signals to customers, reflecting the costs of serving them. For example, an appropriate price signal encourages conservation by customers;
3. Rate changes should be gradual so as to limit rate shock to consumers. Rate stability and continuity are important to both the utility and the consumer; and
4. Rates should be understandable and easy to administer. Maintaining ease in administration helps ensure that customers understand their utility bills better.[91]

115. The first principle recognizes that DEA should be afforded the opportunity to recover its revenue requirement, including recovery of its capital costs, which ties into the notion that in the absence of competition, government regulation attempts to approximate the results that would be achieved in a competitive environment.[92]

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[89] DOC Ex. 301 at 11, 15 (Ruzycki Direct).
[90] *See Matter of Request of Interstate Power Co. for Authority to Change Rates* (*Interstate Power*), 559 N.W.2d 130, 133 (Minn. Ct. App. 1997), *aff'd* 574 N.W.2d 408 (Minn. 1998).
[91] DOC Ex. 304 at 2 (Peirce Direct).
[92] *Id.* at 3.

116. The second principle reflects the goal that rates should send an appropriate price signal to customers by reflecting the cost of serving them. Rates set at marginal cost (the cost of producing the next increment of service) result in an efficient allocation of resources used to produce the incremental unit of service. In other words, an efficient allocation of resources takes place when the value a customer places on a product is equal to the cost of producing the product. Although the costs in the current case are based on the embedded or historical cost of the system, setting rates at or near the embedded cost to serve each customer class should provide adequate price signals to customers.[93]

117. The third principle requires that proposed rates have some continuity with past rates. Rate stability and continuity are important both to the utility and the consumer. *Id.* Consumers benefit by limiting rate shock associated with wide swings in rates, and utilities are afforded the opportunity to recover a steady revenue requirement.[94]

118. Finally, the fourth principle provides that rates should be understandable and easy to administer. Maintaining ease in administration will help ensure that customers have a better understanding about the amounts and parts of their utility bills.[95]

C. Legal Standards Reflected in Rate Design Principles

119. The four rate-design principles reflect Minnesota law. Regulated public utilities can only charge just and reasonable rates.[96] The burden is on the public utility to show that its requested rate change is just and reasonable.[97] Rates must also encourage energy conservation "to the maximum reasonable extent."[98] In that regard, the Minnesota legislature has found that:

> [I]t is in the public interest to review, analyze and encourage those energy programs that will minimize the need for annual increases in fossil fuel consumption by 1990 and the need for additional electrical generating plants, and provide for an optimum combination of energy sources consistent with environmental protection and the protection of citizens.[99]

Minnesota law also encourages rate designs that promote the use of renewable energy.[100] Moreover, if there is any doubt as to the reasonableness of a particular rate design, such doubt must be resolved in the consumer's favor.[101] In other words, in a situation where different rates

[93] *Id.*
[94] *Id.*
[95] *Id.*
[96] Minn. Stat. § 216B.03 (2014).
[97] Minn. Stat. § 216B.16, subd. 4.
[98] Minn. Stat. § 216B.03.
[99] Minn. Stat. § 216C.05.
[100] *Id.*
[101] Minn. Stat. § 216B.03.

appear to be equally valid, the Commission must choose the rate design that favors the consumer.[102]

120. Minnesota law also prohibits public utilities from charging unreasonably discriminatory rates:

> Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers.[103]

Similarly, a "public utility [shall not], as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage."[104] The Commission is also required to consider the ability to pay as a factor when setting public utility rates.[105]

121. Because rates differ among the various classes of service, the Department concluded that there must be a cost basis for any differences to be deemed reasonable, unless one of the rate-design principles above is used to adjust rates.[106]

D. Apportionment of Revenue Responsibility

122. In Direct Testimony, the Department stated that it largely agreed with DEA's proposed apportionment of revenue responsibility, but it recommended providing the Small General Service class with some relief from a rate increase. In Surrebuttal Testimony, however, the Department recommended the following apportionment of revenue responsibility:[107]

Table 4: DOC Proposed Revenue Apportionment

Customer Class	Current Revenue (Col. A)	DEA Proposed Revenue (Col. B)	DOC Proposed Revenue (Col. C)	DOC Surrebuttal Revenue (Col. D)	DOC % Chg. (Col. E)
Residential & Farm	$112,384,414	$115,525,437	$115,525,437	$115,525,437	2.79%
Small Gen. Service	$6,674,522	$7,018,217	$6,874,758	$6,908,130	3.50%
Irrigation	$977,226	$996,728	$996,728	$996,728	2.00%
General Service	$47,909,060	$47,927,869	$48,071,328	$48,037,955	0.27%
C&I Interruptible	$26,594,877	$27,194,022	$27,194,022	$27,194,022	2.25%
Lighting	$1,999,160	$2,019,472	$2,019,472	$2,019,472	1.02%
Total	$196,539,259	$200,681,745	$200,681,745	$200,681,745	2.11%

[102] *Id.*
[103] *Id.*
[104] Minn. Stat. § 216B.07.
[105] Minn. Stat. § 216B.16, subd. 15; DOC Ex. 304 at 4 (Peirce Direct).
[106] *Id.* at 4.
[107] *Id.* at 7; DOC Ex. 305 at 3 (Peirce Surrebuttal).

123. In Rebuttal Testimony, DEA raised the concern that the Department's initial apportionment of revenue responsibility to the Small General Service class did not change the class relationship to cost significantly from the outcome of DEA's previous rate case. In response to DEA's concern in that regard, the Department recommended that revenues apportioned to the Small General Service class increase an additional 0.1 percent from 3.4 to 3.5 percent, as an amount that would not unreasonably burden other classes. In total, revenue responsibility apportioned to the Small General Service class would increase by $33,373 under the Department's revised recommendation. According to DEA's rate schedules, the Small General Service class has 4,630 customers; thus, the Department's revised revenue apportionment would result in an approximately $0.60 per month bill impact per customer. With this modest increase, the Small General Service class would be approximately 3.7 percent below the cost of service compared with 4.1 percent in the Department's original recommendation. Given the modest rate impact this change will have on customers, the Department recommended apportioning slightly more revenue responsibility to the Small General Service class. This apportionment reflects a reasonable compromise with that recommended by DEA regarding revenue responsibility apportionment and a reasonable apportionment of revenue responsibility among all DEA customer classes.[108]

124. In the Settlement Agreement, DEA concurred that the Department's updated apportionment of revenue responsibility is reasonable.[109]

125. The ALJ agrees that the apportionment of revenue responsibility in the Settlement Agreement, is reasonable.

E. Customer Charges

126. The following table summarizes DEA's proposed increases to its customer charges for its Residential, C&I Non-Demand, and C&I Demand customers as well as the Department's proposed changes to the customer charges:[110]

Table 5: Summary of Customer Charges

Class	Customer Costs	Current Customer Charge	DEA Proposed Charge	DOC Proposed Charge
Residential & Farm		$8.00	$10.00	$9.00
Residential & Farm Demand Control	$23.39	$11.00	$13.00	$12.00
Residential & Farm		$11.00	$13.00	$12.00

[108] DEA Ex. 101 at DEA-5, at 4 (Larson Direct); DEA Ex. 126 at 8 (Larson Rebuttal); DOC Ex. 305 at 3–4 (Peirce Surrebuttal).
[109] DEA Ex. 128 at 13 (Settlement Agreement).
[110] DOC Ex. 304 at 10 (Peirce Direct).

Time of Day				
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

1. The Role of Intra-Class Subsidies and Sending Appropriate Price Signals to Customers of the Cost of Service

127. All of DEA's customer (member) classes have customer charges set below the monthly fixed costs of serving a customer. To the extent that customer costs are not recovered through the monthly customer charge, they will be recovered from energy charges paid by all customers within a class. If a customer's total usage and customer charge payments are insufficient to recover the cost of serving an individual customer, costs of serving that customer are recovered through the usage charges paid by other DEA customers/members. In other words, customers who use more energy would pay for costs that they do not impose on the system. Such outcomes, called intra-class subsidies, should be minimized.[111]

128. Because some of the customers with higher usage levels may be low-income customers, the Department supported DEA's proposal for an increase in the customer charge, to limit the unintended consequences on low-income, higher usage customers. The Department balanced this goal with the goal of moderating changes in rate design, over time, however. Consequently, the Department recommended a modest increase in the residential customer charge to begin the process of moving those customers towards cost.[112]

129. In considering why to increase DEA's customer charges at all, the effects of rate-design policies on all customers are important to fully consider. Because of intra-class subsidies, some customers will be made better off under certain rate design policies only at the expense of making things worse for other customers within the same class. For example, low-income customers who use larger amounts of energy would pay lower bills if customer charges were set closer to costs because these customers would not have to pay the subsidy in their energy charge to offset the customer costs that low-use (but not necessarily low-income) customers impose on the system for which they do not pay. While the Commission certainly has latitude to design rates as it sees appropriate, the policies chosen should be based on a well-informed record.[113]

[111] *Id.* at 10–11.
[112] *Id.* at 11.
[113] *Id.* at 12.

130. Requiring some customers to pay for customer-related costs that they do not impose on the system while allowing other customers to avoid paying for the costs they impose on the system could lead to unintended consequences, such as either under-recovery or over-recovery of customer-related costs.[114]

a. Including the Cost of the Primary Line When Determining Whether an Intra-Class Subsidy Exists is Reasonable

131. OAG-AUD witness Mr. Nelson stated that the Department should not have included in its estimate of intra-class subsidies on customer costs the cost of the primary line. However, the cost of the primary line remains a customer cost because it is a necessary component for DEA to be capable to serve any customer, as electricity must be delivered through the primary line to reach any home or business. That cost remains whether a customer uses any electricity in a given month or not. Further, even excluding the cost of the primary line, the proposed monthly customer charge is below the cost of serving a customer, as shown in Table 6 below.[115]

Table 6: Summary of Breakeven Point for Customer Costs Under DEA's Current and Proposed Rates

[114] *Id.* at 12–13; DOC Ex. 305 at 8 (Peirce Surrebuttal).
[115] OAG-AUD Ex. 201 at 7, 14 (Nelson Rebuttal); DOC Ex. 305 at 5–6 (Peirce Surrebuttal).

		$8 Customer Charge (OAG-AUD)	$9 Customer Charge (DOC)	$10 Customer Charge (DEA)
1	Residential customer cost	$11.65	$11.65	$11.65
2	Minus: customer charge[1]	$8.00	$9.00	$10.00
3	Monthly customer costs recovered from energy charge, per customer	$3.65	$2.65	$1.65
4	* 12 months			
5	Annual customer costs recovered in energy charge, per customer	$43.80	$31.80	$19.80
6	* Avg. no. of customers (DEA-1, p. 13,)	95,586	95,586	95,586
7	Total annual customer costs recovered in energy charges	$4,185,791	$3,038,999	$1,892,207
8	Divided by kWh sales (DEA-1, p. 13)	879,773,544	879,773,544	879,773,544
9	Per-kWh recovery of customer costs in the energy charge	$0.00476	$0.00345	$0.00215
(3/9)	Breakeven usage amount (kWh)	767	767	767

With an $8 customer charge, an additional $0.00476 of customer costs would be recovered through the energy charge, whereas an additional $0.00345 per kWh would be added to the energy charge under a $9 customer charge. The difference in the energy charge is $.00131 ($0.00476 - $0.00345) or $0.13 for every 100 kWh of energy usage.[116]

1. Promoting Energy Conservation

132. Regarding energy conservation, while charging a higher energy rate generally encourages a customer to use less energy, there are several factors to consider.[117]

133. First, taken to its logical end, recovering all customer costs through the energy charge would tell DEA's customer-members that there is no cost of being connected to DEA's system; because that is inaccurate information, it would be an inappropriate price signal.[118]

134. Second, because DEA's customers are their members, it is important to ensure that DEA is able to recover, as close as possible, its customer costs. Increasing the customer charge to $9.00 per month is a movement in the right direction.[119]

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[116] DOC Ex. 305 at 7 (Peirce Surrebuttal).
[117] DOC Ex. 304 at 13 (Peirce Direct).
[118] *Id.*
[119] *Id.*

135. Third, DEA's rate design already promotes energy conservation appropriately in several important ways:

- DEA's customers can decrease their bills by using less energy, a rate design that directly promotes energy conservation,

- DEA's customers can decrease their bills by using less energy, a rate design that directly promotes energy conservation,

- DEA offers numerous energy conservation programs, in conjunction with its wholesale provider Great River Energy ("GRE"), including rebates, that encourages its customer-members to use less energy. DEA's energy savings and Conservation Improvement Program ("CIP") spending are reported as part of GRE's CIP program results. (*See* Docket No. E,G999/CIP-13-112.) The costs of DEA's energy conservation programs are appropriately included in DEA's energy charge, thus signaling its customer-members to use less energy.[120]

136. The Department concluded that these essential aspects of DEA's rate design reasonably promote the vital goal of promoting energy conservation.[121] The ALJ agrees.

2. Effect on Low-Income Households

137. The Commission expressed concern in the past that high customer charges could be burdensome to low-income households. The assumption is that the amount of energy used by low-income customers is below the break-even point noted below.[122]

138. Because the effect of intra-class energy subsidies is more significant for low-income customers, ensuring that the assumptions about energy use by low-income and other customers are correct is important to verify whether adoption of a rate design proposal benefits low-income customers. For example, low-income customers who use higher-than-average levels of energy are harmed by adoption of customer charges set below cost, because such low-income customers pay through their energy charge for customer costs imposed by other customers. Therefore, increasing the residential customer charge in a moderate manner helps reduce this effect, as shown in Table 7.[123]

**Table 7: Summary of Breakeven Point for Customer Costs
Under DEA's Current and Proposed Rates**

[120] *Id.* at 13–14.
[121] *Id.* at 14.
[122] *Id.*
[123] DOC Ex. 304 at 14 (Peirce Direct).

		Current Customer Charge/Cost	Proposed Customer Charge/Cost
1	Residential customer cost (DEA-3, p. 3 line 31)	$23.39	$23.39
2	Minus: customer charge	$8.00	$10.00
3	Monthly customer costs recovered from energy charge, per customer	$15.39	$13.39
4	* 12 months	$23.39	$23.39
5	Annual customer costs recovered in energy charge, per customer	$184.68	$160.68
6	* Avg. no. of customers (DEA-1, p. 13,)	95,586	95,586
7	Total annual customer costs recovered in energy charges	$17,652,822	$15,355,545
8	Divided by kWh sales (DEA-1, p. 13)	879,773,544	879,773,544
9	Per-kWh recovery of customer costs in the energy charge	$0.02007	$0.01745
10			
(3/9)	Breakeven usage amount (in kWh)	767	767

The breakeven point estimates the amount of electricity use necessary to allow DEA to recover the remaining customer costs through the energy charge. According to DEA's CCOSS, the residential customer cost is $23.39 per customer per month, compared with the current customer charge of $8.00 per month. The difference between the monthly customer cost and the amount of the customer charge applied to those customer costs – in DEA's case $15.39 per customer per month – must be recovered through the energy charge.[124]

139. The impact on customers of recovering customer costs through the energy charge depends on how much energy a customer uses in a given month. Under current rates, an average customer must use approximately 750 kWh to fully pay for the $23.89 in customer costs from the energy charge. Customers using less than approximately 750 kWh will have a portion of their customer costs paid for by customers using more than approximately 750 kWh of energy usage each month. At 500 kWh per month, a customer's revenues would fall $3.36 short of the necessary $15.39 in customer costs needed to be recovered from the energy charge. ((500*$0.02007/kWh)-$15.39).[125]

140. DEA reports that it has approximately 1,392 residential customers receiving low-income home energy assistance ("LIHEAP"), whose bills average 1,073 kWh per month, which

[124] *Id.* at 15.
[125] *Id.* at 16.

is over 300 kWh more than the breakeven 750 kWh in usage per month.[126] These LIHEAP customers would pay an additional $6.14 per month above their customer costs ((1,073 * $0.02007/kWh))-$15.39) reflecting the recovery of customer costs for customers using less than approximately 750 kWh per month.[127]

Table 8: Summary of DEA Customer Usage

	Low-Income Assistance		**Non-Low-Income Assistance**		**Total**	
	Customers	% of Total	Customers	% of Total	Customers	% of Total
Total	2,174	2.4%	89,028	97.6%	91,202	100.0%
Less than 750	1,392	64.0%	49,903	56.1%	51,295	56.2%
750 kWh or more	782	36.0%	39,125	43.9%	39,907	43.8%

141. The Department recommended a balance between increases in the usage charge and the customer charge because the impact of increases in these two charges can affect different customers in different ways. While some low-income customers with low levels of monthly usage may be affected by a $1 per month increase in the monthly customer charge; however, as noted in the example above, DEA's LIHEAP recipients who have above-average usage would pay, on average, a $6.14 per month increase in their bill, and thus would be harmed even more. Further, such customers would already be paying much higher electric bills than low-us customers. Consequently, the Department recommended balancing an increase to the customer charge with the energy charge by increasing the customer charge by $1.00 per month.[128]

3. The Department's Proposed Customer Charges Are Consistent with Increases in Other Electric Rate Cases

142. The Department also recommends a $1.00 increase to the current $8.00 residential customer charge in light of recent rate cases involving other electric utilities, where the Commission has approved residential customer charges of $8.00-$8.50. DEA has not been in for a rate case since 2009, whereas Minnesota Power's 2009 rate case represented the second rate

[126] The only identified low-income customers in DEA's service area are those participating in income assistance programs. According to DEA's response to DOC IR No. 306 and summarized in Table 8, below, in 2013 a total of 2,174 full year customers received low-income assistance or 2.4% of the total 91,202 total full-year residential customers. DOC Ex. 305 at SLP-S-1 (Peirce Surrebuttal). The remaining 97.6% of DEA customers did not receive low-income assistance, and consequently no information is available on their income status. Of the identified low income customers, 64% used less than 750 kWh per month, the Department's estimated breakeven point. Approximately 56% of the customers for whom no income information is known, however, also used less than 750 kWh per month on average; thus a greater amount of their customer costs would be charged to higher usage customers if the customer charge is maintained at $8 per month than if it is increased to $9 per month. *Id.* at 10.
[127] DOC Ex. 304 at 16, SLP-3 (Peirce Direct).
[128] *Id.* at 16–17.

increase in a year, and Xcel's pending 2013 rate case reflects the latest in a series of rate cases. Because of the length of time between DEA rate cases, a $1 increase in the residential customer charge to $9.00 is reasonable.[129]

4. DEA Has Agreed that the Department's Proposed Customer Charges Are Reasonable

143. DEA ultimately agreed that the Department's proposed customer charges were reasonable and should be adopted.[130]

144. The ALJ agrees that DEA and the Department's Settlement Agreement on customer charges for DEA's various customer classes is reasonable. The Department's recommendations reasonably balance an increase in customer charges with increases in energy charges, limit the effect of intra-class subsidies, and are reasonable in promoting energy conservation.

F. Residential Time-of-Day Tariffs

145. DEA has an existing Residential Time-of-Day Service (Schedule 53) that provides peak and off-peak rates. Peak rates are differentiated between summer (June – August) and all other months. DEA updated its rates to reflect its current costs. In addition, DEA proposes to offer a new Residential Time-of-Day Service (Schedule 55) that will provide further differentiation between peak, intermediate and off-peak periods of the day.[131]

146. The Department recommended approval of DEA's proposed Time-of-Day schedules, including its new Residential Time-of-Day Service (Schedule 55).[132] The ALJ agrees.

G. Geothermal Heat Pump

147. DEA proposed to revise its rates and to close its Geothermal Heat Pump Service to new customers. The Association indicated that its wholesale provider, GRE, is no longer offering Geothermal Heat Pump Service as a special program rate. DEA indicated that customers could take service under its General Service tariff.[133]

148. The Department recommended approval of DEA's proposed rate revision, as well as its proposal to closer Geothermal Heat Pump Service to new customers.[134] The ALJ agrees.

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[129] *Id.* at 11.
[130] DEA Ex. 128 at 14 (Settlement Agreement).
[131] DOC Ex. 304 at 17 (Peirce Direct).
[132] *Id.* at 19.
[133] *Id.*
[134] *Id.*

H. Line Extension Charges

149. Currently, DEA provides a 100-foot allowance for both overhead and underground service extensions. DEA charges its customers a $200 flat fee for the first 100 feet, and an additional $6.80 per foot for extensions exceeding the 100-foot allowance. DEA proposed to reduce the allowance from 100 feet to 75 feet, charge a flat $500 fee for the first 75 feet for all extensions, and $8.30 per foot for each additional foot.[135]

150. After analysis of DEA's proposed changes, the Department determined that DEA has supported its proposed changes, which more accurately reflect the costs of adding new customer-members to DEA's system.[136] The ALJ agrees.

I. Service and Reconnection Charges

151. The Department reviewed DEA's cost support for these charges contained in DEA Ex. 101 at DEA-10 (Larson Direct) and concluded that the proposed charges are supported by the cost information provided by the Association. Thus, the Department recommended approval of the proposed changes.[137] The ALJ agrees.

J. Summary of Department Recommendations

152. DEA concurred with all of the Department's recommendations regarding rate design. The Department's recommended apportionment of revenue responsibility and customer charges, including a $1.00 increase to the residential customer charge, are reasonable and should be adopted.[138]

153. The ALJ agrees that the Department's recommended apportionment of revenue responsibility and customer charges, including a $1.00 increase to the residential customer charge, are reasonable.

CONCLUSION

The ALJ recommends that the Commission determine that the rates filed by DEA have been shown to be just and reasonable pursuant to the Settlement Agreement, the Amendment to the Settlement Agreement, and for the reasons discussed in its briefs. The Settlement Agreement, the Amendment to the Settlement Agreement, the parties' Issue Matrix, and the Department's Initial and Reply Briefs sufficiently support this conclusion.

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[135] *Id.* at 20.
[136] *Id.* at 21.
[137] DOC Ex. 304 at 22 (Peirce Direct).
[138] DEA Ex. 128 at 13–14 (Settlement Agreement).

Dated: January 30, 2015

Respectfully Submitted,

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January 30, 2015

The Honorable LauraSue Schlatter
Minnesota Office of Administrative Hearings
600 North Robert Street
P.O. Box 64620
St. Paul, MN 55164-0620

RE: In the Matter of the Application by Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota
MPUC Docket No. E-111/GR-14-482
OAH Docket No. 80-2500-31796

Dear Judge Schlatter:

Enclosed for filing in the above matter, please find the Reply Brief and Proposed Findings of the Minnesota Department of Commerce, Division of Energy Resources.

By copy of this letter all parties have been served. The Affidavit of Service is also enclosed.

Sincerely,

s/ **Peter E. Madsen**
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Attorney for the Minnesota Department of Commerce Division of Energy Resources

Enclosures

cc: Service List

AFFIDAVIT OF SERVICE

RE: In the Matter of the Application by Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota
MPUC Docket No. E-111/GR-14-482
OAH Docket No. 80-2500-31796

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I, Ann Kirlin, hereby state that on the 30th day of January, 2015, I efiled the attached Reply Brief and Proposed Findings of the Minnesota Department of Commerce, Division of Energy Resources and/or served the same by United States Mail, upon all parties on the attached service list, postage prepaid, by depositing the same at St. Paul, Minnesota.

See attached service list

/s/ **Ann Kirlin**
ANN KIRLIN

Subscribed and sworn to before me on
this 30th day of January, 2015.

/s/ Linda J. Krolick
Notary Public - Minnesota
My Commission Expires January 31, 2020

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