	OAH 15-2500-20339-2 PUC E111/GR-09-175

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota	**FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION**

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This matter came on for an evidentiary hearing before Administrative Law Judge Beverly Jones Heydinger on January 11 and 15, 2010, at the offices of the Public Utilities Commission (Commission) in Saint Paul, Minnesota. Public hearings were held on September 22, 2009, in Apple Valley and Farmington, Minnesota. Public comments were received until September 29, 2009.

A briefing schedule was established at the conclusion of the evidentiary hearing. Posthearing briefs were filed on February 22, 2010, and reply briefs were filed on March 5, 2010. The hearing record closed on March 5, 2010.

Appearances:

Harold LeVander, Jr., and Richard J. Savelkoul, Felhaber Larson Fenlon & Vogt, appeared on behalf of Dakota Electric Association (Dakota Electric or Applicant).

Valerie Means and Julia Anderson, Assistant Attorneys General, appeared on behalf of the Department of Commerce, Office of Energy Security (OES).

William T. Stamets, Assistant Attorney General, appeared on behalf of the Office of Attorney General – Residential and Small Business Utilities Division (OAG).

Jerry Dasinger, Clark Kaml and Michelle Rebholz, Commission Staff, were also in attendance.

STATEMENT OF THE ISSUES

In its Application, Dakota Electric requested an annual increase in its electric rates of approximately $6,029,000, approximately a 3.4 percent increase. The

Commission directed that the contested case analyze whether the requested rate increase is just and reasonable, and specifically, to address the following issues:

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

2. Is the rate design proposed by the Applicant reasonable?

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

The ALJ concludes that the test year revenue increase sought by the Applicant is reasonable, with some adjustments. The ALJ concludes that the rate design, capital structure, cost of capital, and return on equity proposed by the Applicant are reasonable, with some modifications.

Based on the evidence in the hearing record, and the proceedings herein, the Administrative Law Judge makes the following:

FINDINGS OF FACT

Description of the Applicant

1. The Applicant was founded in 1937 as a non-profit, member-owned distribution electric utility. It serves approximately 100,000 members, primarily in Dakota County, with some service to portions of Scott, Rice and Goodhue counties.[1] As a cooperative, the Applicant's rates are not required to be regulated,[2] but the Applicant has elected to be regulated. It is the only rate-regulated electric cooperative in Minnesota.[3]

2. The Applicant is governed by a 12-person board of directors, comprised of member owners.[4]

3. As an electric cooperative, the Applicant allocates any margins or "profits" annually to its member owners.

4. Residential customers make up over 90 percent of the Applicant's customer base and generate about 51 percent of its revenue. Commercial customers account for 48 percent of all revenue, and street lighting and irrigation make up about one percent.[5]

[1] Hearing Exhibit (Ex.) 1 at 2 (Application); Ex. 4 at 1 (Larson Direct).
[2] Minn. Stat. § 216B.026. Citations to Minnesota Statutes are to the 2008 Edition.
[3] Ex. 4 at 2 (Larson Direct).
[4] Ex. 4 at 2 (Larson Direct).
[5] Ex. 4 at 2 (Larson Direct); Ex. 5 at 12 of 22 (Larson Direct, Attach. DEA-1).

5. The Applicant does not generate electricity. It purchases wholesale electricity from Great River Energy, of which it is a member.[6]

Procedural Background

6. The Application was filed on March 12, 2009. The Public Utilities Commission solicited comments on whether the Application was substantially complete, and on May 1, 2009, issued three orders, one finding that the rate case filing was substantially complete, one setting an interim rate schedule, and the Notice and Order for Hearing, referring the matter for a contested case hearing. The parties named in the Notice and Order for Hearing were the Applicant and OES.

7. A prehearing conference was held on May 12, 2009. OAG elected to participate as a party pursuant to Minn. R. 7829.0800, subp. 3.[7]

8. The Notice and Order for Hearing directed the Applicant to file supplemental testimony addressing smart metering. The Applicant filed its Supplemental Testimony on May 15, 2009.[8]

9. Direct, rebuttal and surrebuttal testimony was filed according to the schedule set in the First Prehearing Order, dated May 19, 2009.

10. Pursuant to published notice, public hearings were held on September 22, 2009, in Apple Valley and Farmington.[9]

11. The public comment period closed on September 29, 2009.

12. The evidentiary hearing was held on January 11 and 15, 2010, at the Public Utilities Commission.

13. At the close of the evidentiary hearing, a briefing schedule was set. Initial briefs were filed on February 22, 2010, and reply briefs were filed on March 5, 2010.

The Applicant's Requested Rate Increase

14. The Applicant calculated its operating expenses for the 2008 Test Year at $167,526,599, and added a proposed Rate of Return of 7.41 percent, with a resulting required revenue increase of approximately $6,029,000, or 3.4 percent.[10] The Applicant conducted a Class Cost of Service Study using an "embedded cost" method to allocate its costs to the appropriate rate class.[11] The results provided a comparison of the

[6] Ex. 4 at 2 (Larson Direct).
[7] Citations to Minnesota Rules are to the 2009 Edition.
[8] Ex. 24 (Larson Supplemental).
[9] As of the issuance of this Report, the Affidavits of Publication were not yet available. The Applicant has agreed to file those documents with the Commission as soon as they are available, and the ALJ has determined that supplementing the hearing record with those documents is appropriate.
[10] Ex. 4 at 8 (Larson Direct).
[11] Ex. 4 at 19 (Larson Direct).

calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.[12] Other analyses were also conducted to support the allocation of costs.[13]

15. In proposing rate adjustments, the Applicant attempted to increase its revenue by approximately 3.4 percent to meet its projected costs and provide a reasonable rate of return, and to more closely align class rates and revenues with the cost of providing service. At the same time, the Applicant attempted to avoid abrupt changes to rates and gain member acceptance.[14] Based on these considerations, it proposed the following rate increases:

Residential and Farm Classes	(31, 32, 53)[15]	6.2 percent
Small General Service	(41)	11.8 percent
Irrigation	(36)	15.5 percent
General Service	(46, 54)	1.8 percent
Commercial and Industrial (C&I) Interruptible	(70, 71)	-7.1 percent
Lighting	(44)	10.3 percent

Legal Standards

16. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[16] A reasonable rate enables a utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in the capital market. Minnesota law recognizes this principle when it defines a fair rate of return as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment.[17]

17. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change is just and reasonable. In the context of a rate proceeding, the "preponderance of the evidence" is defined as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory

[12] Ex. 4 at 9, 29 (Larson Direct).
[13] Ex. 4 at 30-35 (Larson Direct).
[14] Ex. 1 at 2-3 (Application); Ex. 4 at 36 (Larson Direct).
[15] Numbers in parentheses refer to Applicant's rate classes.
[16] Minn. Stat. § 216B.03.
[17] Minn. Stat. § 216B.16.

responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[18]

18. The Commission acts in both a quasi-judicial and partially legislative capacity. It evaluates the facts, including the claimed costs, and also evaluates the reasonableness of placing the burden of the costs on the ratepayers.[19]

Summary of Public Comments

19. Public hearings were held on September 22, 2009. The afternoon hearing was held at the Apple Valley Community Center, 14603 Hayes Road, Apple Valley, Minnesota. The evening hearing was held at Dakota Electric Association, 430 220th Street West, Farmington, Minnesota. A total of eight members of the public signed the Public Hearing Register at the two sessions.

20. The public comment period was open until September 29, 2009, and approximately 19 written comments were submitted, some from persons who also appeared at one of the public hearings. Most members of the public objected to a rate increase, or to the size of the increase. A few public comments were submitted to the Applicant and were added to the record at the public hearing on September 22, 2009.[20]

21. The chief objection to the rate increase was that it would be difficult for rate payers to pay any increase in light of the economic recession.[21] In particular there were objections by those who live on a fixed income.[22] Two public members suggested that the Applicant develop a "senior citizen rate" for such persons.[23]

22. Two members of the public complained that the Applicant had failed to provide sufficient detail about the basis for the requested rate increase.[24] Some requested that the Applicant make greater efforts to reduce its costs, as its customers must do when costs rise and income does not.[25]

23. The Resource Tax Adjustment (RTA) allows the Applicant to pass through annually its changes in wholesale power costs, conservation program spending, and

[18] *In re Northern States Power,* 416 N.W.2d 719, 722 (Minn. 1987).
[19] *Id.*
[20] Comments--Public Hearing Ex. 1 and Comments Received By ALJ (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=20099-42143-01).
[21] *See e.g.,* Eugene Fritzinger (September 4, 2009); Nancy Casada (August 28, 2009); Ralph and Deborah Hanson (September 14, 2009); Robert McCormick (September 25, 2009).
[22] *See, e.g.,* Maria B. Murad (January 12, 2009); Hubert Ludwig (September 10, 2009); Marilyn Micholic (September 14, 2009); Glenda Ballis (afternoon hearing).
[23] Richard A. LeMay (Correspondence received September 8 and September 24, 2009; and evening hearing); Marilyn Micholic (September 14, 2009).
[24] Mary Nell LeClair (January 7, 2009); Donald Kern (evening hearing).
[25] *See* Raymond Yarwood (September 25, 2009).

property taxes.[26] One person, Lynn King, objected to the RTA pass-through because she did not believe that it gave the Applicant sufficient incentive to control its costs.[27]

24. Daniel Burke wanted some assurance from the Applicant that it would upgrade service in certain areas.[28] Leann Lehman and Mick and Michelle Webb were generally complimentary of the Applicant's service but objected to the amount of the proposed increase.[29]

25. Joyce Osborne objected to the increase in light of the recession and declining demand. She was also concerned because the Applicant purchases power from Great River Energy, which she asserted was overly dependent on coal for generation and could shift its costs for new transmission lines, including the planned 345 kV Brookings to Hampton line, to the Applicant's customers.[30]

Revenue Requirement

26. The Applicant's revenue requirement is its total cost of doing business, comprised of its operating expenses, depreciation expenses, taxes and a margin sufficient to meet its capital costs.[31] To determine whether a rate increase is needed, the Applicant compares its revenue requirements against its present revenue. In its Application, the Applicant projected operating expenses totaling $167,526,599, a rate base of $161,512,444, and a proposed rate of return of 7.41 percent on that base, resulting in a total revenue requirement of $178,583,520. In order to meet this requirement, the Applicant calculated a required revenue increase of approximately $6,028,969, or 3.4 percent.[32]

27. In the regulated utility industry, the Commission must assure that the price (rates) are sufficient to cover the cost of doing business, including a fair rate of return, so that the utility can compete for necessary funds in the capital markets.[33]

<u>Test Year Rate Base</u>

28. In order to evaluate a utility's revenue requirement and the adequacy of its present rate structure, the utility will analyze its revenue and expenses for a 12-month period, the "Test Year", and establish its rate base.

29. The operating expenses were calculated for a 2008 Test Year. The Test Year revenue requirements were based on the Applicant's actual historical operations for calendar year 2008, with adjustments for known and measurable changes. Exhibit 5

[26] Transcript T. Vol. 2 at 58 (Larson).
[27] Lynn King (January 28, 2009).
[28] Daniel Burke (evening hearing).
[29] Leann Lehmann (September 7, 2009); Mike and Michelle Webb (September 14, 2009).
[30] Joyce Osborne (afternoon hearing); Public Hearing Exhibit 1.
[31] Ex. 38 at 2 (Amit Direct).
[32] Ex. 4 at 8, Table 1 (Larson Direct).
[33] Ex. 38 at 2 (Amit Direct).

sets forth the Applicant's 2008 actual revenue and expense, and the adjustments made for the 2008 Test Year.[34]

30. In its calculation, the Applicant included only "operating" revenue and expenses, which are those associated with its basic function of supplying electric service to its members. The Applicant excluded "non-operating income," such as interest earnings from short-term investments and patronage capital credit assignments from associated organizations. Its stated reason for excluding non-operating income was that such income is outside of the Applicant's operation and control.[35]

31. The Applicant proposed test-year net operating income of $5,027,952.[36] OES recommended two adjustments to expenses, totaling $123,922, resulting in adjusted test-year operating income of $5,151,874.[37] The Applicant agreed with the adjustments.[38]

32. The Applicant has a for-profit wholly-owned subsidiary holding company, Midwest Energy Services (MES), which has two wholly-owned companies: Energy Alternatives, Inc. (EAI), formerly named Dakota Energy, provides and installs standby power generators for large commercial industrial customers; Consulting Engineers Group, Inc. (CEG) provides engineering consulting services.[39]

33. OES reviewed the Applicant's cost allocations between the unregulated and regulated activities according to guidelines set forth by the Commission in Docket 1008 and later clarifying orders.[40] OES determined that services contracted from the Applicant's subsidiaries and for CEG's facilities and equipment, and intercompany charges are formalized through annual lease agreements. The subsidiaries' books are kept separately and the net income of the consolidated subsidiaries is separately indentified. All revenue and expenses related to the Applicant's non-regulated activities are separately tracked, and recorded to the appropriate Federal Energy Regulatory Commission accounts.[41]

34. OES concluded that the Applicant used a fully distributed cost methodology and was able to identify and isolate all non-regulated investments, that it appropriately identified direct non-utility expenses, and that its allocation procedures

[34] Ex. 4 at 12-13 (Larson Direct).
[35] Ex. 4 at 15 (Larson Direct).
[36] Ex. 4 at 15 (Larson Direct).
[37] Ex. 32 at 14-15, LL-6 (La Plante Direct)(Decrease in Distribution-Operation Expense of $81,724; Decrease in property taxes of $42,198).
[38] Ex. 22 at 5 (Larson Rebuttal).
[39] Ex. 32 at 5 (LaPlante Direct).
[40] Ex. 32 at 7-8 (LaPlante Direct)(referring to *ITMO an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Order Setting Filing Requirement, Docket No. G,E999/CI-90-1008 at 4 (September 28, 1994) ("Docket 1008" or "*Docket 1008 Order*")).
[41] Ex. 32 at 6 (LaPlante Direct).

were, in general, reasonable and in reasonable compliance with the Commission's *Docket 1008 Order*.[42]

Rate Base

35. The Applicant proposed a rate base of $161,512,444.[43] OES identified adjustments to the depreciation reserve and cash working capital, a net adjustment of $290,472, with an adjusted rate base of $161,221,972.[44] The Applicant agreed with the adjustments.[45]

Sales Forecast

36. The Commission must decide the likely amount of revenue that the Applicant will obtain through sales of electricity during the projected test year. Applicant included a sales forecast in its Application.[46] OES reviewed the forecast and noted some minor differences in calculations and weather data. It recommended that, in the future, the Applicant use consistent weather data sources. The Applicant agreed with OES's recommendations.[47]

37. OES concluded that the Applicant's methodology, data and calculations were reasonable and the energy sales volume and budgeted customer counts could be verified.[48]

38. The Applicant's sales forecast results in a test-year deficiency of $6,028,969 under present rates.[49]

Rate of Return

39. The concept of a fair rate of return (ROR) is, by definition, the rate which, when multiplied by the rate base, will give the utility a reasonable return on its total investment, including a return that is sufficient to enable the utility to attract capital to provide reasonable service to its customers.[50] The ROR is based on a projected capital structure including debt and equity and, when applied to its rate base, is an amount that a utility can recover to meet the cost of interest on its debt, attract capital, and maintain a desired equity position.[51]

[42] Ex. 32 at 8-9 (LaPlante Direct).
[43] Ex. 4 at 8 (Larson Direct).
[44] Ex. 32 at 10 (reducing depreciation expense adjustment by $296,892); *Id.,* at 13 (increasing test-year cash working capital requirement by $6,420, total adjustments of $290,472) (La Plante Direct, and Attachment LL-3).
[45] Ex. 22 at 4-5 (Larson Rebuttal).
[46] Ex. 4 at 14 (Larson Direct); Ex. 5 (Larson Direct, DEA-1).
[47] Ex. 22 at 6 (Larson Rebuttal).
[48] Ex. 31 at 3-7 (Shah Direct).
[49] Ex. 33 at 2 and Attach. LL-8 (LaPlante Surrebuttal).
[50] Minn. Stat. § 216.16, subd. 6; Ex. 38 at 2 (Amit Direct).
[51] Ex. 4 at 16 (Larson Direct).

40. In the regulated utility industry, the regulatory agencies ensure that utilities provide an appropriate supply of satisfactory services at reasonable rates because, as a utility, its costs are not subject to a competitive environment. However, the utility must be able to compete in the capital markets and assure a sufficient return to investors to attract the capital required to provide services to its customers.[52]

41. A utility is not entitled to large profits but its return:

> should be reasonable, sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[53]

42. The Applicant differs from the typical investor-owned utility in that all of its ratepayers are also the only investors in the utility. The equity portion of the Applicant's capitalization is termed "patronage capital," since it is collected from the Applicant's customers through rates. In effect, a portion of every customer's electric bill is "earmarked" as a capital credit. The Applicant must return this capital to the Applicant's customers on a regular basis.[54] For a cooperative, the ROR must result in sufficient margins to:

- Pay interest expense on long-term debt;
- Rotate patronage capital according to schedule; and
- Maintain or achieve the desired equity position.[55]

43. The Applicant's proposed rate of return of 7.41 percent was based on: 1) a blended cost of debt of 5.81 percent; 2) a five-year growth in total capitalization of 5.54 percent; 3) achieving an equity position of 40 percent, and 4) returning $1,500,000 of patronage capital annually.[56] The effective cost of equity was 6.26 percent.[57]

<u>Applicant's Proposed Capital Structure</u>

44. To determine an overall rate of return on capital for a utility, the costs of long-term debt and the rate of return on equity must be weighted by the ratio of each component in the overall capital structure. The Applicant proposed that its ROR be calculated using the following capital structure:[58]

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[52] *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia,* 262 U.S. 679 (1923).
[53] *Id.,* at 693.
[54] Ex. 38 at 5 (Amit Direct).
[55] Ex. 4 at 16 (Larson Direct).
[56] Ex. 4 at 17 (Larson Direct).
[57] Ex. 38 at 21 (Amit Direct).
[58] Ex. 6 (Larson Direct, DEA-2).

Component	$ Amount	Capitalization
Equity	$94,900,838	47.68%
Debt	$104,140,399	53.32%
Total	$199,041,237	100.00%

Return on Equity

45. The fair rate of return on equity is the utility's cost of equity capital.[59] As outlined by the federal courts, the following guidelines are commonly applied to determine the cost of common equity capital for a regulated electric utility:

- 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.[60]

46. The Applicant proposed a return on equity (ROE) of 6.26 percent. For a cooperative, the ROE is calculated differently than it is calculated for investor-owned utilities. Because its ratepayers are also the only investors in the cooperative, the Applicant's equity portion of its capitalization is properly termed "patronage capital" and is collected from its customers through rates. A portion of every customer's electric bill is "earmarked" as capital credits and used to maintain a sound capital structure.[61]

47. The patronage capital credits must be returned to the Applicant's customers on a regular basis. Based on its historical experience, the Applicant has determined that it needs to return $1,500,000 a year as capital credits.[62]

48. An appropriate ROE will be sufficient to retire capital credits and finance growth in the equity portion of the utility's rate base.[63]

49. To determine a fair ROE, the Applicant followed a certain methodology that tied the growth rate in equity to the growth rate of total assets. Its calculated return on equity was designed to permit the rotation of capital, taking into account its projected rate of growth in total capitalization.[64] The Applicant selected the most recent five year period to estimate the average annual growth rate in total capitalization, taking into

[59] Ex. 38 at 2 (Amit Direct).
[60] *Bluefield, supra*, *Federal Power Comm'n v. Hope,* 320 U.S. 591, 603 (1944)**;** Ex. 38 at 3 (Amit Direct).
[61] Ex. 38 at 5 (Amit Direct).
[62] Ex. 4 at 17 (Larson Direct).
[63] Ex. 38 at 7-8 (Amit Direct).
[64] Ex. 4 at 17 (Larson Direct).

account construction plans and changes in the cost of materials. Also, it asserted that its historic growth rate is more conservative than its forecasted growth rate.[65]

50. The Applicant set a goal of 40 percent equity ratio, calculated by dividing equity by total assets. Thus, to maintain the 40 percent equity ratio, its equity must grow at the same annual growth rate as its total assets. In calculating its projected growth, the Applicant applied a five-year average historical growth rate in total capital of 5.54 percent rather than projecting the growth of total assets. OES asserted that, to maintain an appropriate equity to assets ratio, the projected growth rate should be driven by the projected growth rate of total assets, and not total capital. Although OES acknowledged that, absent projected growth rates of total assets, it was reasonable for the Applicant to use historical trends to estimate future expected growth rates, in this instance, the Applicant had forecasted annual total assets from 2009 through 2018. Using this information, and applying log linear regression, OES confirmed the accuracy of the Applicant's projected ROE, and supported a return on equity of 6.26 percent.[66]

51. However, OES preferred a different approach to calculating the ROE. It determined that the more appropriate method was to set a ratio of equity to total capital, rather than equity to assets. It calculated an equity to total capital ratio that would correspond to the Applicant's desired equity to assets ratio of 40 percent. Based on this approach, OES derived the same percentage figure that the Applicant had, 6.26 percent, but OES asserted that its method was better supported and appropriately accounted for the differences between cooperatives and independently-owned utilities, and therefore preferable to the Applicant's approach.[67] The Applicant agreed to accept the OES approach and to employ it in future rate cases.[68]

52. OAG asserted that the Applicant's proposed ROE was too high. It criticized the Applicant's reliance on five-year historic data to calculate the average annual growth rate in total capitalization at 5.54 percent. If the growth rate is too high, the ratepayers will pay excessive rates to fund the overly-optimistic growth rate.[69] Instead, OAG proposed looking at data over a longer period to better smooth out the annual variations. To demonstrate the volatility, OAG noted that the selection of four years rather than five years of data would have yielded a capital growth rate of 4.29 percent rather than 5.54 percent. OAG selected an eight-year period, the same period that the Applicant used to calculate weather normalization for its sales forecast. OAG calculated that the eight-year historical average results in a capital growth rate of 4.99 percent.[70] Using this figure, OAG calculated the ROE at 5.78 percent.[71]

53. Neither the Applicant nor OES agreed with the OAG's analysis. They believed that the OAG was incorrect because it used the wrong 2008 total asset number

[65] Ex. 22 at 26-27 (Larson Rebuttal).
[66] Ex. 38 at 10 and Attachment EA-2 (Amit Direct).
[67] Ex. 38 at 11-12 and Attachment EA-3 (Amit Direct).
[68] Ex. 22 at 3-4 (Larson Rebuttal).
[69] Ex. 25 at 6 (Smith Direct).
[70] Ex. 25 at 7-9 (Smith Direct).
[71] Ex. 25 at 9 (Smith Direct).

and because it used only two data points, actual assets for 2008 and forecasted assets for 2013. Moreover, the time period to normalize weather is unrelated to the time period for averaging capital growth.[72]

54. Ultimately, OAG took the position that the Commission should adopt the methodology initially proposed by the Applicant, based on the growth rate of total assets, as adjusted to use an eight-year historical period to smooth out the volatility of the historical growth rates, yielding a growth rate of 4.99 percent and an ROE that is based on that figure.[73]

55. In light of the lack of a coherent independent analysis by the OAG, and the consistent results yielded by the Applicant's and OES's approaches, the evidence supports a return on equity of 6.26 percent.

Cost of Debt

56. The Applicant requested blended cost of debt of 5.81 percent. The costs of long-term debt are embedded historical costs, calculated by using the outstanding balances of the utility's existing long-term loans combined with their interest rates. The costs are adjusted for known and measurable changes.[74]

57. Since the early 1990's, the Applicant has obtained all of its long-term financing from the National Rural Utilities Cooperative Finance Corporation (CFC).[75] For 36 different transactions, with interest rates ranging from 3.8 percent to 7.4 percent, the Applicant's blended cost of debt is 5.81 percent, which favorably compares with Minnesota investor-owned utilities. The Applicant periodically reviews the cost of debt from CFC as compared to other lenders, and has found that, for long-term borrowing, CFC has offered it the best rates. The Applicant has also received other benefits from CFC that are not available from other lenders.[76]

58. The parties disagreed over the proper treatment of interest rate discounts that the Applicant typically receives from CFC. The Applicant may receive three interest rate discounts from CFC if it meets certain conditions. In order to attain the "performance discount", the Applicant must attain a "modified debt service coverage" (MDSC) ratio of not less than 1.35, calculated as an average of the two highest ratios in the most recent three years.[77] There are two other discounts available, a "volume discount" for long-term debt in excess of $15 million, and a "collateral discount" for a borrower that places all of its long-term debt with CFC. However, the Applicant cannot earn either the volume discount or the collateral discount unless the MDSC calculation remains at 1.35 or above so that the performance discount criteria is met.[78] The

[72] Ex. 22 at 26-27 (Larson Rebuttal).
[73] Initial Brief of OAG at 9-10; Ex. 25 at 9 (Smith Direct).
[74] Ex. 39 at 3 (Amit Surrebuttal).
[75] Ex. 22 at 23 (Larson Rebuttal); T. at 27-28 (Larson).
[76] Ex. 22 at 23 (Larson Rebuttal).
[77] The precise calculation is set forth in Ex. 38 at 15 (Amit Direct).
[78] T. Vol. 1 at 29-32 (Larson).

combined total of the three discounts was approximately $497,000 in 2008. The Applicant estimated its 2009 MDSC to be 1.88, which would qualify for the discounts.[79]

59. In calculating its cost of debt at 5.81 percent, the Applicant did not deduct the three interest rate discounts from its cost of debt.[80] Although the Applicant will receive the discounts for 2009, it excluded the discounts from its debt calculation because both 2008 and 2009 were poor financial years for the Applicant. If 2010 is similarly poor, the Applicant may not qualify for the performance discount and would lose the benefit of all three discounts. In light of the uncertainty about the future, the Applicant did not believe that it was prudent to include the discounts in its cost calculation.[81]

60. In determining the revenue requirement, both test-year revenues and test-year expenses must represent typical or “business-as-usual” levels of revenues and costs. But if the costs or revenues are unique or not expected to regularly repeat, adjustments should be made to the test year calculation.[82] The loan discounts were given to the Applicant during the test year, which reduced its test-year embedded cost of long-term debt. If the discounts are expected to repeat every year with a high degree of certainty, they should be included in the debt cost calculation.

61. OAG asserted that the discounts should be applied to the cost of debt because the Applicant had achieved the required MDSC ratio for at least 15 years and was unable to identify a year when it had not earned the discounts.[83] Because the discounts have been earned consistently, they should be treated as a “business-as-usual” reduction to the cost of debt. OAG deducted the total discount, approximately $497,000, from interest expense, reducing the cost of long-term debt from the Applicant’s proposed 5.81 percent to 5.34 percent. OAG also pointed out that the discounts had been included in the Applicant’s long range financial forecast for 2008-2018.[84]

62. OES took the position that the debt discounts should not be treated as business-as-usual reductions to expense because the Applicant does not have reasonable control over all the variables that affect the Applicant’s ability to meet the criteria. However, it also acknowledged that the Applicant had consistently benefitted from the discounts in prior years. In an effort to balance the historical experience with the future uncertainty, OES proposed that half of the total discounts be deducted from the interest expense, a discount of $248,696. By dividing that expense by the total loan balance, the OES concluded that the appropriate long-term debt costs should be 5.58 percent.[85]

[79] Ex. 2 (Application Workpapers).
[80] T. Vol. 1 at 34 (Larson).
[81] Ex. 22 at 24-25 (Larson Rebuttal); T. at 30-31 (Larson).
[82] Ex. 39 at 3 (Amit Surrebuttal).
[83] T. Vol. 1 at 30-32 (Larson).
[84] Ex. 27 at 3 (Smith Surrebuttal); Ex. 2, No. 5 (Workpapers).
[85] Ex. 39 at 5 (Amit Surrebuttal).

63. The Applicant objected to any reduction to the interest expense, which it claimed failed to recognize the many external influences on financial performance, including the weather and the faltering economy, which the Applicant is unable to control. If the discounts are not received, interest payments will not be recoverable, which could compel the Applicant to file another rate case sooner than would otherwise be necessary. Conversely, if the Applicant over-recovered for its interest cost, it asserted that its margin would be allocated to the member-owners in the future. The Applicant noted that neither OES nor OAG could state with a high degree of certainty that the discounts would be earned.

64. The Applicant explained that the discounts were included in the forecast because the Applicant predicted it would attain 1.5 MDSC over the period, but if that prediction was not met, the discounts would not take effect. It was an input to the forecast, but not a predicted outcome of the forecast. Because the discounts were uncertain, the Applicants maintained that the discounts should not be built into the cost of debt.[86].

65. The discounts are "business as usual" and should be included in the interest expense calculation. Although it is possible that the Applicant will not earn the discount in the future, it has consistently earned them in the past. The Applicant failed to offer any evidence that the components of the MDSC have significantly changed in a way that will impact the probability of earning the discounts in the future. Although the OES has proposed counting half of the discounts, there is no evidence to support a "50/50 chance." Absent any evidence that the variables that make up the MDSC will significantly change in the future, the Applicants should include the discounts in its interest expense calculation.

66. Also, as pointed out by the OAG, because it is probable that the Applicant will be granted a rate increase, its income will rise, enhancing its operating margin. This will improve the Applicant's ratio and increase the likelihood that the MDSC target will be reached.

67. The cost of debt should be reduced to 5.34 percent.

68. OAG questioned the Applicant's reliance on CFC financing and recommended that the Applicant be required to demonstrate in its next rate case that its long-term interest expense is prudently incurred by offering data of rates from other lenders.[87] The Commission may choose to address the issue in the Applicant's next rate proceeding.

Capital Structure

69. The Applicant's proposed return on rate base was calculated according to a methodology used by its lender, the CFC.[88] Its proposed capital structure was based

[86] T. Vol. 1 at 33 (Larson).
[87] OAG Initial Brief at 7.
[88] Ex. 4 at 16 (Larson Direct).

on a 40 percent target equity to total asset ratio, with 47.68 percent equity and 52.32 percent debt.[89] Its imputed capital structure, using a 40 percent target equity to total assets ratio, would be 44.61 percent equity and 55.39 percent debt. This is not a significantly different capital structure. Based on its analysis, OES concurred that the Applicant's proposed test-year capital structure was reasonable.[90]

Overall Cost of Capital

70. The ALJ recommends that the return on equity be established at 6.26 percent and the recommended cost of debt at 5.34 percent. Applying these figures to the capital structure, the overall cost of capital is 5.75 percent, derived as follows:

	Percentage of Total Capital	**Cost Rate %**	**Weighted Cost %**
Equity Ratio	44.61	6.26	2.79
Long-Term Debt	55.39	5.34	2.96
Total	100.00		5.75

71. OES noted that the overall rate of return on total capital must be adjusted to allow the Applicant to earn the same amount on its rate base as it would earn on its total capitalization. OES proposed that the appropriate adjustment reflect the impact of regulatory treatment of various assets having the effect of not including them in the Applicant's rate base.[91] Applying this approach and incorporating the recommended cost of debt results in the following formula for arriving at the appropriate rate of return:

Overall return on rate base = 5.75 x Total Capitalization/Approved Rate Base[92]

72. Since the total capitalization and approved rate base will be determined by the Commission in this proceeding, the rate of return should be re-calculated by the Commission once those figures are known.

Class Cost of Service Study (CCOSS)

73. Once the revenue requirement is calculated, the utility must determine the appropriate rates to charge each rate class to generate the required revenue. Typically, the first step in determining the appropriate rate design is to conduct a "class cost of service study" (CCOSS). The purpose of the CCOSS is to attempt to identify the actual cost of providing service to each rate class, based on its load and service

[89] Ex. 6 (Larson Direct, DEA-2 at 6).
[90] Ex. 38 at 16 (Amit Direct).
[91] Ex. 38 at 17-18 (Amit Direct).
[92] Ex. 38 at 18-19 (Amit Direct).

characteristics. Expenses are allocated to classes using factors that attempt to reflect an underlying relationship between the expense and the class. Although there is a relationship between the expense and the class, it may not always be precise. The results of the CCOSS are a starting point to establish the rates so that revenue is recovered from each customer class at a level that takes its costs into account.

74. Although it is a useful tool for evaluating cost responsibility, the CCOSS analysis cannot precisely determine the actual costs of serving each rate class. It employs certain assumptions that may affect the results. It attempts to determine costs imposed by a rate class and not by the individual customers within each classification, and is based on assumptions about the demand characteristics and load factor for the individual classes. It is generally accepted that the CCOSS should be used to determine a range of class cost responsibility and not precise values.[93]

75. The Applicant followed the CCOSS model approved by the Commission in its last rate case, with a refinement to reflect a change in GRE's wholesale energy rates, discussed below.[94] In conducting the CCOSS, the Applicant allocated Test Year expenses to accounts, following the Uniform System of Accounts provided by the Federal Energy Regulatory Commission. Then it attempted to identify the costs directly attributable to a specific customer class (direct costs), costs which do not vary significantly with demand (consumer or customer costs), costs which result from being ready to operate at peak demand (capacity or demand costs), and costs related to the amount of energy used by a class of customer (energy costs). With this information, the Applicant assigned the costs of providing service to each class of customer. Then, the Applicant determined the revenue by class from present rates, the revenue required to meet the costs allocated to the class, and the difference between the two. The results of the Applicant's CCOSS are set forth below, as revised.[95]

[93] Ex. 4 at 20 (Larson Direct); Ex. 35 at 2 (Ouanes Surrebuttal).
[94] Ex. 4 at 22 (Larson Direct); Docket No. E111/GR-03-261.
[95] Ex. 4 at 29 (Larson Direct); Ex. 46, Table 6-Revised; T. Vol. 1 at 16 (Larson).

Table 6 - REVISED Cost of Service Summary				
Rate Class	Revenue Present Rates	Revenue Requirement	Increase (Decrease) Amount	Percent
	($)	($)	($)	(%)
Residential & Farm (31,32,53)	94,043,350	102,192,609	8,149,260	8.4
Small General Service (41)	5,230,575	5,987,344	756,769	14.0
Irrigation (36)	843,862	977,889	134,027	15.4
General Service (46,54)	43,863,812	43,321,024	(542,788)	-1.2
C&I Interruptible (70,71)	24,700,707	22,068,322	(2,632,385)	-10.3
Lighting	1,596,499	1,760,585	164,086	9.9
Total System				3.4

76. The Applicant determined the costs for each class of the power supply, transmission and distribution, and summarized the unit cost per consumer in each class as follows:[96]

Table 8 Unit Cost Summary			
Rate Class	Consumer Unit Cost	Demand Unit Cost	Energy Unit Cost
	($/cust.mo.)	(¢/kWh)	(¢/kWh)
Residential & Farm (31,32,53)	23.35	4.23	4.15
Small General Service (41)	27.66	4.38	4.15
Irrigation (36)	62.87	3.00	4.15
General Service (46,54)	68.27	4.11	4.15
Interruptible Service (70,71)	183.94	0.84	4.15
Street and Security Lighting	0.47	2.92	3.64

77. The Commission has approved the “fully allocated average embedded cost” approach for allocating cost responsibility to the various classes and developing rate design information.[97]

78. The Applicant purchases power from Great River Energy (GRE). The wholesale cost of the energy makes up the largest portion of its costs to serve members. For the CCOSS allocation, the Applicant assigned the energy costs to the class that incurred them, including only those demand-related charges incurred by the

[96] Ex. 4 at 30 (Larson Direct).
[97] *See ITMO the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-08-1065 (Commission Findings of Fact, Conclusions of Law, and Order issued October 23, 2009)**.**

class.[98] Energy charges amount to 72 percent of the costs in the CCOSS.[99] The Applicant used a fully embedded cost methodology to allocate the remaining 28 percent of costs based on its costs to distribute the power to its customers. Costs recorded on the Applicant's books[100] are allocated on an average system-wide basis. Detailed calculations and assumptions are set forth in Exhibit 7.

79. The Applicant performed several other cost analyses to support the CCOSS.[101]

80. OAG objected to the embedded cost approach to the CCOSS, particularly as a method of allocating the joint and common costs.[102] The January 1992, Electric Utility Cost Allocation Manual of the National Association of Regulatory Utility Commissioners (Manual) defines "joint and common" costs. It states:

> Joint costs occur when the provision of one service is an automatic by–product of the production of another service. Common costs are incurred when an entity produces several services using the same facilities or inputs … In the electric industry, the most common occurrence of joint costs is the time jointness of the cost of production where the capacity installed to serve peak demands is also available to serve demands at other times of the day or year. Overhead expenses such as the president's salary or the accounting and legal expenses are examples of costs that are common to all of the separate services offered by the utility.[103]

81. It is necessary to exercise judgment in the allocation of joint and common costs in conducting an embedded cost study.[104]

82. The Commission has consistently approved the embedded cost approach to the CCOSS. As pointed out by OES, the OAG's preferred approach, to use a marginal cost study, has its own limitations.[105] Also, OAG has not conducted its own CCOSS, nor has it analyzed whether a change in the allocation of the joint and common costs would affect the outcome of the CCOSS.[106]

83. The OAG raised questions in its Rebuttal Testimony about the allocation of the capacity-related wholesale power and transmission charges to the interruptible classes. OAG asserts that GRE's charges understate the actual costs of delivering that power, which leads to over-allocating the Applicant's costs to other rate classes. OAG also argued that the primary line costs should have no customer-related component.

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[98] Ex. 22 at 19-21 (Larson Rebuttal); Ex. 23 at 8-11 (Larson Surrebuttal).
[99] T. Vol. 2 at 17 (Lindell).
[100] Ex. 4 at 19 (Larson Direct).
[101] Ex. 4 at 30 (Larson Direct); Exs. 8, 11, 12, 14, 15, 16, 20, and 21 (Attachments to Larson Direct).
[102] Ex. 29 at 3 (Lindell Rebuttal).
[103] Manual at 15; Ex. 35 at 3 (Ouanes Surrebuttal).
[104] *Id.*
[105] Ex. 35 at 5 (Ouanes Surrebuttal).
[106] T. Vol. 2 at 11, 15-22 (Lindell).

However, the Manual includes both a customer component and a demand component to the primary line costs.[107]

84. OES acknowledged that there were some questions concerning the statistical reliability of the zero-intercept method used by the Applicant to classify distribution plant accounts. Although the information provided by the Applicant was sufficient to set rates at this time, more refined cost data would be beneficial. It recommended that the Commission require the Applicant in its next rate case to use the minimum-intercept method to classify its costs or to support the reasonableness of the zero-intercept method.[108] The Applicant has agreed to this suggestion.[109]

85. The Resource and Tax Adjustment (RTA) allows the Applicant to pass through annually its changes in wholesale power costs, conservation program spending, and property taxes.[110] The Applicant has concluded that passing through the wholesale power cost charges to the Commercial and Industrial (C&I) Interruptible classes (Schedules 71 and 72) and Interruptible Irrigation class (Schedule 36) has imposed a cost on those classes that they did not incur and should have been attributed to firm-service classes. In 2008, the interruptible-service classes saw an increase in 20 percent to their charges because of the RTA.[111] On the CCOSS, that is reflected as overpayment by those classes.

86. The Applicant submitted a miscellaneous filing to the Commission in 2008 to address this, but the Commission directed the Applicant to address the issue in its next rate case.[112] The Applicant proposed an alternative Energy Cost Adjustment (ECA) base for the interruptible classes. The ECA presently includes only wholesale energy costs, but in future years, the Applicant may include some portion of transmission and ancillary service costs.[113]

87. The OAG objected to the manner in which the Applicant's CCOSS allocated transmission and capacity related costs among its rate classes. Although the C&I Interruptible classes consume approximately 22 percent of the megawatt hours that the Applicant purchases from GRE, and the Applicant incurs approximately $15.7 million of transmission-related costs for all megawatt hours purchased, the Applicant allocated only $132,192 of transmission costs, less than one percent, to the C&I Interruptible class. In comparison, the Residential and Farm class consumes 46 percent of the electricity that the Applicant purchases from GRE, but more than $9.6 million of the $15.7 million of transmission related costs, approximately 62 percent, is allocated to the Residential and Farm class.[114] The Applicant incurs approximately $33 million of wholesale capacity-related charges, but assigns only $250,000 to the C&I

[107] Manual at 90: Ex. 35 at 6 (Ouanes Surrebuttal).
[108] Initial Posthearing Brief of OES at 40; Ex. 35 at 7 (Ouanes Surrebuttal).
[109] Initial Brief of Applicant at 8.
[110] T. Vol. 2 at 58 (Larson).
[111] T. Vol. 2 at 58-59 (Larson).
[112] T. Vol. 2 at 59 (Larson).
[113] Ex. 4 at 33 (Larson Direct).
[114] Ex. 7 at 2 of 46 (Larson Direct, DEA-3).

Interruptible class, and more than $20 million, approximately 61 percent, to the Residential and Farm class.[115]

88. The OAG maintained that the small amount of cost allocated to the C&I Interruptible classes significantly and inappropriately reduces the rates to those classes, and contributes to inappropriately high rates for the Residential and Farm and Small General Service classes.[116] The result of the misallocation of costs is that the interruptible customers receive deeply discounted rates, which, OAG claims, may benefit the Applicant's for-profit subsidiary EAI. EAI provides project management for stand-by generators for commercial and industrial customers to provide back-up power.[117]

89. Although OAG agreed that all customers benefit when some large customers agree to interruptible service, it asserted that the significant reallocation of costs away from the C&I Interruptible classes is not justified. As additional evidence, OAG showed that in 2007, service to the interruptible customers was interrupted on only seven days, totaling approximately 39 hours for the partially interruptible rate class and 58 hours for the fully interruptible rate class. Likewise, in 2008, there were nine days in which customers were interrupted for a total of 58 hours for the partially interruptible customers and 64 hours for the fully interruptible class, in total, less that one percent of the time. During the vast majority of the time, the C&I Interruptible classes were using the same generation and transmission as the other classes.[118]

90. OAG has raised a valid question about the Applicant's allocation of the wholesale power and transmission costs. The C&I Interruptible classes benefit from the investment and operation of the transmission in closer relation to its use of those resources, which is considerably in excess of one percent. It is not obvious that transmission resources would be increased if the service could not be interrupted. However, the allocation of the capacity costs is better justified because without the ability to interrupt service at peak demand, the Applicant would face greater capacity costs. The savings associated with interruption, reflected in the lower costs that the Applicant pays for wholesale power to serve that class, should inure to the class.

91. The Applicant maintained that it is merely passing through GRE's charges.[119] However, as OAG points out, GRE's wholesale rates are not regulated by the Commission and may not directly reflect underlying infrastructure costs.

92. OES found that the Applicant's proposed CCOSS was generally reasonable, and that the refinement to reflect GRE's wholesale energy rates better matched the Applicant's wholesale energy costs to its customer classes.[120]

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[115] *Id.,* Ex. 29 at 9-11 (Lindell Rebuttal).
[116] Ex. 28 (Lindell Direct, JJL-2).
[117] Ex. 4 at 3-4 (Larson Direct).
[118] Ex. 29 at 9 and JJL-1(Lindell Rebuttal).
[119] Ex. 23 at 10 (Larson Surrebuttal).
[120] Ex. 34 at 5-6 (Ouanes Direct).

93. On the evidence in this record, there is no basis to compel the Applicant to attribute different amounts for wholesale power and transmission than it is charged by GRE. Applicant is justified in charging only those costs to the C&I Interruptible class that the Applicant pays to GRE. However, OAG has pointed out significant differences in the proportion of resources used by the rate classes and the wholesale rates that GRE charges. The Commission may wish to conduct a closer investigation into how the wholesale rates are reflected in the retail rates of GRE's members. Although the Commission does not regulate wholesale rates, it is responsible for assuring that the retail rates, including the wholesale cost component, are just and reasonable.

Rate Design

94. The Applicant's proposed rate design attempted to develop rates sufficient to recover its revenue requirement and reflect the cost of providing service to each class. Although the Applicant attempted to minimize the extent that one class or subclass subsidized or was subsidized by another class or subclass, it also attempted to maintain relatively simple rate schedules and avoid abrupt changes to the rates for any rate class. Other considerations were to promote the efficient use of energy and system capacity and maintain a rate schedule competitive with neighboring utilities and alternative energy sources.[121]

95. The four principles of rate design articulated by OES are:

- Rates should be designed to allow the Applicant a reasonable opportunity to recover its revenue requirement, including the cost of capital;

- Rates should promote the efficient use of resources;

- Rate changes should be gradual in order to limit the rate shock to consumers; and

- Rates should be understandable and easy to administer.[122]

96. These principles are based on the provisions of Minnesota statutes, which require that rates must be reasonable and not unreasonably discriminatory either by class or by person.[123] Rate design should favor energy conservation and the use of renewable energy.[124] Doubts about the reasonableness of the rates should be resolved in favor of the consumer.[125]

[121] Ex. 4 at 36 (Larson).
[122] Ex. 36 at 2-3 (Peirce Direct).
[123] Minn. Stat. §§ 216B.07 and 216B.03.
[124] Minn. Stat. §§ 216B.03, 216C.05.
[125] Minn. Stat. § 216B.03.

97. The Applicant's goals were consistent with the approved principles of rate design.[126]

98. The Applicant's initial rate request would have increased revenue by approximately $5,998,752, or 3.36 percent, apportioned in Applicant's initial rate design as follows:[127]

Comparison of Revenue
Present and Proposed Rates

(a) Line No.	(b) Rate Class	(c) Revenue Present Rates ($)	(d) Revenue Proposed Rates ($)	(e) Increase (Decrease) Amount ($)	(f) Increase (Decrease) Percent (%)
1	Residential & Farm Service (31)	98,416,062	104,516,896	6,100,834	6.20
2	Residential & Farm Demand Control (32)	38,891	41,380	2,489	6.40
3	Irrigation Service (36) Firm	89,640	150,802	61,162	68.23
4	Irrigation Service (36) Interruptible	783,165	853,180	70,015	8.94
5	Small General Service (41)	5,503,820	6,142,401	638,581	11.60
6	Security Lighting Service (44)	141,348	157,506	16,158	11.43
7	Street Lighting Service (44-2)	400,079	447,214	47,135	11.78
8	Street Lighting System (44-1)	54,084	56,740	2,656	4.91
9	Custom Residential Street Lighting (44-3)	1,055,745	1,154,964	99,219	9.40
10	Low Wattage Unmetered Service (45)	4,368	4,992	624	14.29
11	General Service (46)	44,895,910	45,678,736	782,826	1.74
12	Municipal Civil Defense Sirens (47)	3,780	3,780	-	-
13	Geothermal Heat Pump (49)	11,307	18,792	7,485	66.20
14	Controlled Energy Storage (51)	295,488	315,187	19,699	6.67
15	Controlled Interruptible Service (52)	1,865,523	2,025,907	160,384	8.60
16	Residential & Farm Time of Day (53)	27,789	29,953	2,164	7.79
17	General Service Time of Day (54)	472,354	475,711	3,357	0.71
18	Standby Service (60)	95,280	98,280	3,000	3.15
19	Full Interruptible Service (70)	23,762,138	22,045,019	(1,717,119)	(7.23)
20	Partial Interruptible Service (71)	1,785,760	1,744,313	(41,447)	(2.32)
21	Cycled Air Conditioning Service (80)	(1,307,715)	(1,569,258)	(261,543)	20.00
22	**Total**	178,394,816	184,392,495	5,997,679	3.36

99. The Applicant's rate design attempted to provide a reasonable opportunity to recover its revenue requirement, ensure that each class was given responsibility for the costs caused by the class, as identified in the CCOSS, avoid dramatic rate changes, and establish understandable rates.

100. The rate design included a "seasonality factor," that is, the proposed rates reflect one energy (or demand) rate in the months of June, July and August (summer months), and lower energy (or demand) rate for the remaining nine months of the year. The seasonality factor was implemented in the Applicant's last rate case, Docket No. E-111/GR-03-261.[128]

[126] Ex. 36 at 2 (Peirce Direct).
[127] Ex. 4 at 38 and DEA-6 at 6 (Larson Direct); Ex. 10.
[128] Ex. 4 at 31, 38-39 (Larson Direct); Ex. 11 (Larson Direct, Attach. DEA-7).

Residential and Farm Service Classes (Classes 31, 32, 53)

101. Based on the CCOSS results, the revenue from the Residential and Farm Service classes would have to increase by 8.4 percent to fully recover the costs of service. The Applicant proposed a smaller increase, raising the fixed monthly charge from the present $7.00 to $8.00, and increasing the energy charge as well. The proposed increase would "zero" the present RTA and result in an increase to the Residential and Farm Service classes of approximately 6.2 percent.[129]

Small General Service (Class 41)

102. Based on the CCOSS results, the revenue from the Small General Service class would have to increase by 14 percent to fully recover the costs of service to that class. The Applicant proposed a smaller increase, raising the fixed monthly charge from the present $8.00 to $10.00 and increasing the energy charge as well, a revenue increase of about 11.0 percent for the class.[130]

Irrigation Service – (Class 36)

103. The CCOSS showed the need to increase revenues from Irrigation services in the amount of $134,000, or about 15.4 percent to meet the Applicant's cost for the class. However, the CCOSS showed a need for about a 10 percent increase from interruptible irrigation customers (approximately 295), and about a 68 percent increase for firm irrigation customers (approximately 20). Because of the few firm customers and the large projected increase, the Applicant proposed to contact each firm irrigation customer to encourage them to move to the interruptible rate. Customers who chose to remain with firm irrigation service would be charged for the full cost of service, but the rate increase would be phased in over a three-year period.[131]

104. Some of the firm irrigation service customers are large nurseries. Because the cost of lost trees and shrubs may exceed the cost of the increased electric rates, the Applicant anticipated that some may chose to retain firm service. These businesses will see a steep increase in their electric rates. OES agreed that phasing in an increase was appropriate and apparently agreed that the increase was reasonable.[132]

105. It appears that the usage by interruptible customers greatly exceeds usage by the firm customers. The cost difference in the CCOSS for the firm and interruptible irrigation classes suggests that, like with the C&I Interruptible class, the low cost reflects the rates charged by GRE. Thus, although the firm irrigation class uses about 6.3 percent of the energy, it will bear about 14.4 percent of the cost.[133]

[129] Ex. 4 at 39 (Larson Direct).
[130] Ex. 4 at 43-44 (Larson); Ex. 47 (*Errata* to Ex. 4, page 43, line 20).
[131] Ex. 4 at 41-43, Table 12 and Table 13 (Larson Direct).
[132] Ex. 36 at 17 (Peirce Direct).
[133] Ex. 36 at SLP-6, page 2 (Peirce Direct)

106. Since the firm customers will have the option to shift to interruptible service, and since the total increase will be phased in over three years, the Applicant has demonstrated that its revenue allocation for Irrigation service is reasonable.

Commercial and Industrial Interruptible Service (70, 71)

107. Based on the CCOSS results, the revenue from the C&I Interruptible class exceeded the costs by about 10.3 percent. As explained in the discussion of the CCOSS, the Applicant attempted to address this overpayment by reducing the costs allocated to the class. Also, the Applicant wanted to assure that customers that move from the General Service Class to interruptible service benefit from the reduced cost to provide wholesale power for interruptible service. For that reason, the Applicant proposed retaining the monthly fixed charge of $75.00 and adjusting the charges for transmission service to conform with the actual charges incurred through the Applicant's system that is coincident with each GRE monthly coincident billing peak. For wholesale billing purposes, C&I customers would only pay demand-related wholesale charges when those customers failed to control their usage and thereby triggered a demand billing.[134] The Applicant also proposes to eliminate RTA charges to the C&I customer class because capacity costs do not apply to Schedules 70 and 71, and a recent increase in RTA charges to these customers was not cost justified.[135]

108. OES proposed limiting the increase to the Small General Service and Irrigation classes to 10 percent, and offsetting that revenue reduction with a slightly lower reduction from the C&I Interruptible class.[136] The Applicant largely agreed, but proposed that both the C&I Interruptible and General Service customers bear some of the reduction.[137] OES agreed to this modification,[138] and their agreement is reflected as follows:

Summary of OES Proposed Revenue Apportionment[139]

Customer Class	Current Revenue (Col. A)	DEA Proposed Revenue (Col. B)	OES Proposed Revenue (Col. C)	OES/ DEA Agreement	% of Total Rev. (Col D)	% Increase in Revenue (Col. E)	% from Cost Over-(Under) (Col. F)
Residential & Farm	$94,043,350	$99,906,063	$99,906,063	$99,906,063	56.7%	6.0%	(2.2%)
Small Gen. Service	5,230,575	5,850,387	5,753,633	5,753,633	3.3%	9.7%	(3.9%)
Irrigation	843,862	$975,039	$928,248	$928,248	0.5%	9.7%	(5.1%)
General Service	43,863,812	$44,649,995	$44,649,995	$44,744,717	25.4%	1.9%	3.3%
C&I Interruptible	24,700,707	$22,942,141	$23,085,686	$22,990,964	13.1%	(6.7)%	4.2%
Lighting	1,596,499	$1,761,667	$1,761,667	$1,761,667	1.0%	10.0%	0.1%
Total	$170,278,805	$176,085,292	$176, 085,292	$176, 085,292	100.0%	3.4%	(0.1%)

[134] Ex. 23 at 9 (Larson Surrebuttal).
[135] Ex. 22 at 21-22 (Larson Rebuttal).
[136] Ex. 36 at 7 (Peirce Direct).
[137] Ex. 22 at 9 (Larson Rebuttal).
[138] Ex. 37 at 1-2 (Peirce Surrebuttal).
[139] Ex. 36 at 7 (Peirce Direct); Ex. 22 DEA-3 (Larson Rebuttal), as modified.

109. The Applicant and OES maintained that these changes in revenue apportionment will move the customer classes closer to cost.

110. Since the OAG disagreed that the Applicant had correctly allocated costs to the classes, it also objected to the level of increase in revenue apportionment to some of the classes. In order to better balance what it perceived were inappropriate cost allocations to the Residential and Farm and Small General Service classes, and taking into account the need to assure that interruptible service customers were charged less than those receiving firm service, the OAG proposed that the increase to the Residential and Farm class not exceed four percent, that the increase to the Small General Service class not exceed five percent, and that the current C&I Interruptible rate of 5.9 cents per kWh remain the same. Its proposed rates would generate revenue of approximately $4.2 million, which it claimed was "the bulk" of the Applicant's requested $6 million.[140] OAG did not prepare a chart that would show the percent over/under cost for each customer class that would result from its proposal, although the percentage below cost for Residential and Farm and Small General Service classes would be greater than proposed by the Applicant.

111. When the revenue apportioned to a class of customers fails to recover the costs of serving those customers, the difference is made up by over-recovering from other classes, referred to as "inter-class subsidies." Although it is important to minimize inter-class subsidies, other factors are considered. First, the CCOSS is an approximation of costs to the classes, but does not perfectly reflect actual costs. If costs to a class are overstated, the class may pay more than it should and conversely, if the costs to the class are understated, the class may pay too much. Second, changes to the rates should not be so abrupt that customers experience rate shock. In each rate case, the utilities attempt to move their revenue apportionment closer to their costs, decreasing inter-class subsidies, while at the same time minimizing rate shock. The Applicant and OES believed that their agreed upon revenue apportionment both decreased inter-class subsidies and minimized rate shock.

112. OAG disagreed. It asserted that rate shock is particularly difficult for residential ratepayers because they cannot pass along increases to their customers, as the commercial classes can, and because personal income is not rising. Also, for persons on low or fixed income any increase is a hardship. In this economy, imposing a 6.2 percent increase on the Residential and Farm classes will be hardship, as was reflected in the public comments received. As OAG pointed out, the Applicant's method of allocating costs to the C&I Interruptible class leads to the conclusion that the class is contributing above its costs, but if more costs are allocated to the class, based on its use of transmission and capacity, then the class revenue apportionment may be closer to the costs.

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[140] Ex. 29 at 12 (Lindell Rebuttal).

113. The OAG is correct that if the costs are not properly allocated, the comparison of revenue to costs is also incorrect. However, any change to the revenue apportionment would have to be supported by a different cost allocation, for which there is insufficient evidence in this record. Thus, the desire to moderate the increase to the Residential & Farm Service class falls into the category of a non-cost factor that the Commission may take into account in determining whether the rate increase to the Residential and Farm and Small General Service classes should be reduced and other classes moved upward to adjust for the possible inaccuracies in cost allocation.

114. As an additional point in support of its position, OAG pointed out that the increase in required revenue agreed upon by the Applicant and OES is $5,902,088**.** This amount is roughly comparable to the increased revenue allocation to the Residential and Farm Service class. Increases to the other classes are roughly offset by the decreased revenue allocation to the C&I Interruptible class, $1,709,743. (Table 4). Although it is inaccurate to conclude that the Residential and Farm Service class is shouldering virtually all of the rate increase, the comparison does point out the effect on other rate classes of significantly decreasing the revenue allocation to the C&I Interruptible class.

115. The results of the CCOSS show that the Residential and Farm Service class revenue is 8.4 percent below the costs to the class. The Applicant's proposed revenue allocation would reduce that difference to 2.2 percent. The results of the CCOSS show that the C&I Interruptible class paid 10.3 percent over its allocated costs. The Applicant's proposed revenue allocation would drop the overpayment to 4.2 percent.

116. Although the CCOSS should provide guidance to the process, the significant reduction in revenue apportioned to the C&I Interruptible class will result in an unacceptable increase in the rates for the Residential & Farm Service class. Although OES proposed slight reductions to the Small General Service and Irrigation classes, no modifications were made to the Residential & Farm Service class.

117. It is reasonable to bring revenue closer to cost, but the size of the reduction to the C&I Interruptible class should be further modified to ease the size of the increase to the Residential & Farm Service class. The decrease in revenue obtained from the C&I Interruptible class should be limited to 5.15 percent, which will cut in half the amount the class pays above cost, and move the costs and revenues closer to alignment. The revenue from the class would decrease from current levels by approximately $1,272,086, to $23,428,621. With this change recommended by the ALJ, the class will enjoy a slightly smaller benefit from the cuts, but the increase to the Residential & Farm Service class can be further moderated. The increased revenue apportioned to the Residential & Farm Service class would be reduced from $5,862,713 to $4,590,627. An increase of approximately 4.9 percent will still move the Residential and Farm Service class closer to cost, and it is still significantly higher than the rate increase as a whole. Although such an increase will be difficult for some of the class members to bear, it will assure that the Applicant receives the revenue required to

deliver service to its customers as its own costs rise. The changes resulting from the differing apportionments between classes are as follows:

Class	CCOSS	Proposed	ALJ Recommendation
Residential & Farm (31,32,53)	8.4%	6.0%	4.9%
Small General Service (41)	14.0%	9.7%	9.7%
Irrigation (36)	15.4%	9.7%	9.7%
General Service (46,54)	(1.2)%	1.9%	1.9%
C&I Interruptible (70,71)	(10.3)%	(6.7)%	(5.15)%
Lighting	9.9%	10.0%	10.0%

118. The foregoing chart uses the revenue requirement figure agreed upon between the Applicant and OES in arriving at the recommended modifications by class. If the Commission approves a different revenue requirement than used for the foregoing chart, the Commission should use the revenue apportionment percentages agreed upon by the Applicant, modified to increase the percentage allocated to the C&I Interruptible class and decrease the percentage allocated to the Residential and Farm Service classes.

Fixed monthly charges

119. In virtually every rate case, there is an attempt to raise the fixed monthly charge so that the utility is able to recover a greater proportion of its fixed costs and reduce its dependence on the use of energy to generate the balance of the revenue required to meet fixed costs. One purpose of the CCOSS is to examine the differential between the costs per class and the amount of revenue generated through the fixed monthly charge. At the same time, the Legislature has emphasized that rates should encourage conservation, and it is perceived that raising the fixed monthly charge discourages conservation because it weakens the link between consumption and cost.

120. The Applicant has proposed increases to the fixed monthly charges. OES recommended modifications to the proposed charges, and the Applicant accepted the modifications set out in the following chart:[141]

[141] Ex. 36 at 9 (Peirce Direct); Ex. 22 at 9 (Larson Rebuttal).

Class	Customer Costs	Current Customer Charge	Applicant and OES Proposed Charges
Residential & Farm (31,32,53)	$23.35	$7.00	$8.00
Small General Service (41)	$27.66	$8.00	$10.00
Irrigation (36)	$62.87	$22.00	$24.00
General Service (46,54)	$68.27	$25.00	$25.00
C&I Interruptible (70,71)	$183.94	$75.00	$75.00

121. OES supported increased monthly charges to minimize intra-class subsidies. It explained that intra-class subsidies arise when some customers within a class pay in excess of the cost to serve them while other customers within the same class pay less than that cost. That is, if the full cost of connecting and keeping a customer on the system is not recovered through the fixed monthly charge, the costs associated with those services will be recovered through the energy charge. As a result, customers with higher monthly usage will pay higher energy costs and will also pay for the customer costs that were not recovered through the fixed monthly charge.[142]

122. OES offered the following 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."[143] In support of the example, OES calculated the break-even point for residential customers under the current and proposed rates to be about 800 kWh.[144] It showed that 52,496 residential customers who use an average of less than 800 kWh (about 57 percent of all customers) will have a portion of their customer costs paid by customers using more than 800 kWh of energy usage each month. Yet of the 52,496 customers, only about two percent (approximately 994) are low income customers. OES data also show that only about one percent of customers using more than 800 kWh of energy (38,921) are low income (approximately 451).

123. OES asserted that the higher users are paying some of the customer costs for lower energy users, even though the vast majority of the lower users are not classified as low income. An increase in the fixed monthly charge will assure that the higher energy users are not subsidizing the lower energy users, thus reducing the impact of intra-class subsidization. With an increase to the fixed monthly charge, the

[142] Ex. 36 at 10-13 (Peirce Direct).
[143] Ex. 36 at 11 (Peirce Direct).
[144] Ex. 36 at 13 (Peirce Direct).

average bill for customers using less than 800 kWh hours will increase slightly more than the average bill for customers using more than 800 kWh.[145]

124. The OAG opposed any increase to the fixed monthly charge for the Residential and Farm and Small General Service classes and favored recovering any allowed revenue increase through the energy charge. It contended that this maintains the important link between energy consumption and cost. This position also reflects the public's view that fixed rate increases are unfair when the economy is in a recession and that fixed income ratepayers, in particular, cannot afford any increase. By increasing only the energy charge, it sends the signal that lowering consumption will lower the charge to the customer, and that the customer will directly benefit from improvements in energy efficiency.[146]

125. Although the OAG may correctly present public perception, the monthly charge should be set to cover a significant portion of the minimum cost to serve the customer. If the charge is too low, high energy users will in fact pay too much – not only to cover their energy use, but also to defray costs to serve low-use customers. If the energy charge more closely correlates to energy use, it will minimize the intra-class subsidy, and should be a sufficient incentive to conserve.

126. An increase of $1.00 will bring the fixed monthly charge for residential customers to $8.00, a level consistent with the charges recently approved in other rate cases. If the revenue allocation agreed upon by the Applicant and OES is accepted, the increase in the fixed monthly charge is also reasonable and should be approved. However, if the ALJ's recommended allocation is approved, a smaller increase to the fixed monthly charge may be sufficient to minimize the intra-class subsidy.

The other monthly charges agreed upon by the Applicant and OES are reasonable and should be approved.

Other Tariff Issues

Line Extension Charges

127. In any year, the Applicant has few line extensions charged to the customer, typically 17 to 20 per year. It is more typical that line extensions occur in new residential developments with the developer bearing the cost. Of the extensions that are charged to the customer, most are underground.[147] Under the current tariff, the Applicant provides a 400-foot allowance for both overhead and underground service extensions and connection. Customers with an underground extension are charged a $200 flat fee for the first 400 feet, and an additional $2.70 per foot for extensions exceeding the 400-foot allowance. For an overhead extension, customers are not

[145] Ex. 36 at 15 (Peirce Direct).
[146] Ex. 26 at 8-9 (Lindell Direct); Initial Brief of OAG at 16-20.
[147] T. Vol. 1 at 66 (Larson).

charged a fee for the first 400 feet, but are charged $2.40 per foot for extensions exceeding the 400-foot allowance.[148]

128. The Applicant proposed a flat $200 fee for all line extensions up to 100 feet and $6.80 per foot for each additional foot.[149] OES evaluated the Applicant's expenses for "typical" extensions, but noted that there were relatively few to include in the calculation. Based on the extensions included in the analysis, it appeared that the $200 fee would cover about 100 feet of extension, and that $6.80 for each additional foot would cover about half of the 2008 average cost per foot. OES concluded that the Applicant's proposed tariff changes were reasonable, but if the Applicant should see an increase in the number of overhead extensions, it should include that information in the Applicant's annual report to the Commission on electric distribution reliability, safety and other matters.[150] The ALJ recommends approval of the line extensions charges.

Service Fees

129. The Applicant proposed several adjustments to its special service fees. OES summarized these changes as follows:[151]

Service Charge	Current	Proposed	Change Increase/(Decrease)
Meter Test at Customer Request			
Single Phase	$80.00	$75.00	($5.00)
Three Phase	$90.00	$85.00	($5.00)
Returned Check Charge	$15.00	$15.00	-
Reconnection Charge (after disconnect, same customer)			
Self-Contained meter	$50.00	$45.00	($5.00)
Normal Working Hours	$100.00	$120.00	$20.00
After Hours			
Transformer-Rated meter			
Normal Working Hours	$95.00	$150.00	$55.00
After Hours	$195.00	$270.00	$75.00
Service Charge (Outside normal working hours, when problem is not DEA equip.)	$200.00	$270.00	$70.00
Load Mgmt Service Charge			
Normal Working Hours	$50.00	$60.00	$10.00
After Hours	$100.00	$120.00	$20.00
Pulse Meter	$450.00	$350.00	($100.00)
Temporary Service			
Non-winter months	$150.00	$200.00	$50.00
Winter months	$250.00	$325.00	$75.00
Transfer/Connection	$17.50	$17.50	-

130. OES analyzed the Applicant's cost support for the charges, set forth in Exhibit 14, determined that the charges were supported by the cost information, and recommended that the charges be approved. There was no evidence to the contrary in

[148] Ex. 4 at 32, 55-56 (Larson Direct); Ex. 36 at 17 (Peirce Direct).
[149] Ex. 4 at 32 (Larson Direct).
[150] Ex. 36 at 18-19 (Peirce Direct).
[151] OES Brief, at 56 (drawn from Ex. 36 at 20 (Peirce Direct), Ex. 4 at 55 (Larson Direct); and Ex. 14).

the record of this proceeding. The ALJ recommends approval of the special service fees.

Lighting

131. OES noted that the Applicant proposed to close its tariffs for new customers for lighting based on mercury technology because the technology is less efficient than high-pressure sodium and few customers are taking service under the tariffs.[152] While there appears to be no discussion of the issue, the Applicant's request appears reasonable and consistent with the overall approach to reducing mercury in the environment. The Applicant has demonstrated that its proposed changes to its tariffs are reasonable and should be approved.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. Ch. 216B and section 14.50.

2. Any foregoing Finding which contains material which should be treated as a Conclusion is hereby adopted as a Conclusion.

3. The Applicant has shown that the issues that have been resolved by the parties result in rates that are in the public interest and those issues should be approved by the Commission.

4. The Applicant has shown that its proposed capital structure accurately reflects an appropriate division of debt and equity and should be adopted in calculating required revenue.

5. The Applicant has demonstrated that its proposed return on equity (ROE) strikes an appropriate balance between the interests of its customers as holders of patronage capital and these same customers as ratepayers. The ROE figure of 6.26 percent is appropriate and should be used to determine the allowable return on revenue (ROR) in this matter.

6. OES has demonstrated that its methodology to compute the ROE is better justified, and the Applicant has agreed to use that methodology in its next rate case.

7. The Applicant has not shown that its proposed cost of long-term debt, 5.81 percent, is reasonable. OAG has shown that the Applicant is likely to incur long-term debt cost of 5.34 percent. OES has not shown that its proposed long-term debt figure is

[152] Ex. 36 at 20-21 (Peirce Direct); Exs. 18 and 19.

supported by evidence in the record. The reasonable cost of long-term debt is 5.34 percent.

8. The Applicant has demonstrated that its appropriate allowable ROR should include $1,500,000 a year for the return of patronage capital credits to its customers.

9. Determination of the Applicant's appropriate allowable ROR should be calculated by application of the OES formula of overall return on rate base = 5.75 x Total Capitalization/Approved Rate Base.

10. The Applicant has shown that an adjusted rate base of $161,221,972 is appropriate for rate setting purposes.

11. Use of the year on ending December 31, 2008, with adjustments for known and measurable changes as the projected test year for determining the Applicant's revenue requirement is reasonable. The forecast of the total of the Applicant's electricity sales, agreed to by both OES and the Applicant, is reasonable. Calculation of the net required revenue requirement is dependent upon the determination of the various issues before the Commission in this proceeding.

12. The Applicant has demonstrated that it will experience a substantial revenue shortfall. The Applicant is entitled to recover this revenue shortfall through an adjustment of its electric rates to increase its revenues.

13. The Applicant has not demonstrated that its proposed allocation of the rate increase across customer classes meets the Commission's standards for rate design. The allocation agreed upon by the Applicant and OES should be adjusted to increase the portion attributed to the Applicant's C&I Interruptible class of customers and reduce the portion attributable to the Residential and Farm class. The resulting allocation will strike the best balance between the Commission's rate design principles.

14. The Applicant has demonstrated that an increase in the residential fixed monthly charge from $7.00 per month to $8.00 per month is an appropriate adjustment to balance the need to recoup the costs of serving the residential class of customers without interclass subsidies, with the need to encourage conservation, avoid rate shock, and account for other factors between rate classes, but subject to possible reduction if the Commission adopts the ALJ's recommended revenue allocation. Based on the record in this proceeding, the Applicant has demonstrated that the other proposed adjustments to the monthly charges are appropriate and meet the Commission's standards for changes in rates.

15. Modifying the Applicant's electric rates in the manner described in the Findings and Conclusions above results in just and reasonable rates that are in the public interest within the meaning of Minn. Stat. § 216B.11.

16. The proposed changes in tariff provisions are reasonable and should be approved.

17. The rate finally ordered by the Commission should be compared to the interim rate set in the Commission's May 1, 2009 Order Setting Interim Rates, and a refund ordered to the extent that the interim rate exceeds the final rate, subject to any true-up ordered regarding any particular expense.

Based upon these Conclusions, and for the reasons explained in the accompanying Memorandum, the Administrative Law Judge makes the following:

RECOMMENDATIONS

IT IS RECOMMENDED that the Public Utilities Commission order that:

1. The Applicant is entitled to increase gross annual revenues in the manner and in an amount consistent with the terms of this Order.

2. Within 30 days of the service date of this Order, the Applicant shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement for annual periods beginning with the effective date of the new rates, and the rate design decisions contained herein. The Applicant shall include proposed customer notices explaining the final rates. Parties shall have 14 days to comment.

3. If the Commission orders an Interim Rate Refund within 30 days of the service date of this Order, the Applicant shall file with the Commission for its review and approval, and serve upon all parties in this proceeding, a proposed plan for refunding to all customers, with interest, the revenue collected during the Interim Rate period in excess of the amount authorized herein. Parties shall have 14 days to comment.

Dated: April 5, 2010

s/Beverly Jones Heydinger
Beverly Jones Heydinger
Administrative Law Judge

Reported: Shaddix & Associates

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission (Commission) and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 15 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, Metro Square Building, Suite 350, 121 7th Place East, St. Paul, Minnesota 55101-2147. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions of Law and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument with their filed exceptions or reply. Exceptions should be e-Filed with the Commission.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that the recommendation has no legal effect unless expressly adopted by the Commission as its final order.

MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS

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April 5, 2010

Dr. Burl W. Haar
MN Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101

Re: *In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota;* OAH Docket No. 15-2500-20339-2
PUC E111/GR-09-175

Dear Dr. Haar:

Enclosed herewith and served upon you by electronic service is the Administrative Law Judge's Findings of Fact, Conclusions, and Recommendation in the above-entitled matter. The official record will follow under separate cover.

Sincerely,

s/Beverly Jones Heydinger
BEVERLY JONES HEYDINGER
Administrative Law Judge

Telephone: (651) 361-7838

BJH:nh

cc: All Parties as listed on the Certificate Service

Encl.