OAH 80-2500-31796
PUC E-111/GR-14-482

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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

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

An evidentiary hearing was held in this matter before Administrative Law Judge LauraSue Schlatter on December 18, 2014, in the Small Hearing Room at the Public Utilities Commission, 350 Metro Square Building, 121 Seventh Place East, St. Paul, Minnesota.

The following appearances were made:

Harold Levander, Felhaber Larson L.L.P., appeared on behalf of the Applicant, Dakota Electric Association (DEA).

Peter Madsen and Linda Jensen, Assistant Attorneys General, appeared on behalf of the Minnesota Department of Commerce, Division of Energy Resources (Department).

Ian Dobson, Assistant Attorney General, appeared on behalf of the Office of the Attorney General – Antitrust and Utilities Division (OAG).

Andrew Bahn, Dorothy Morrissey, Robert Harding and Ganesh Krishnan, staff of the Public Utilities Commission (Commission) were also present at the hearing.

The Administrative Law Judge convened public hearings on December 2, 2015 at the Apple Valley Senior Center, 14601 Hayes Road in Apple Valley, Minnesota, at 2:00 p.m.; and at the Dakota Energy Association, 4300 220th Street West, in Farmington, Minnesota, at 7:00 p.m.

A briefing schedule was established at the first prehearing conference. DEA filed a post-hearing issues matrix on January 9, 2015. The parties filed initial post-hearing briefs on January 20, 2015. Reply briefs and proposed findings of fact were filed by all parties on January 30, 2015, and the record closed on that date.

STATEMENT OF ISSUES

On July 2, 2014, DEA filed a petition to increase its electric rates in Minnesota. DEA asked to increase electric rates by approximately $4,189,000, or approximately 2.1 percent per year. The Commission has directed that an evidentiary record be established on DEA's petition, and the following issues be addressed:[1]

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

2. Is the rate design proposed by DEA reasonable?

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

The Commission also asked the parties to address and provide schedules and supporting documentation in the development of the record in this matter to show the matching of power cost revenue to power cost expense in the pro forma test year financial schedules.

FINDINGS OF FACT

I. DESCRIPTION OF THE COMPANY

1. DEA was founded in 1937. It is a nonprofit, member-owned Minnesota corporation. DEA serves more than 103,000 members and is engaged in the distribution of electric energy in Dakota County and portions of Scott, Rice, and Goodhue Counties in Minnesota.[2]

2. DEA is only a distribution utility. It does not generate electricity or own any high voltage transmission lines. Instead, it purchases its wholesale power and related transmission services from Great River Energy (GRE) of Maple Grove, Minnesota.[3]

3. A twelve-person elected Board of Directors, consisting of members of the nonprofit corporation, governs DEA.[4]

II. JURISDICTIONAL AND PROCEDURAL BACKGROUND

4. The Commission has general jurisdiction in this matter pursuant to Minn. Stat. § 216B.01, .026 (2014). These statutes provide for regulation of cooperative electric associations if the members elect to become subject to rate regulation by the Commission.

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[1] NOTICE AND ORDER FOR HEARING at 2 (August 29, 2014) (eDocket 20148-102661-01).
[2] Ex. 100 at 2 (Miller Direct); Ex. 101 at 1 (Larson Direct).
[3] Ex. 100 at 2 (Miller Direct).
[4] *Id.*

5. In 1980, a majority of DEA members elected to be subject to rate regulation by the Commission, and DEA rates have been regulated by the Commission since 1981.[5]

6. On July 2, 2014, DEA filed a general rate case petition seeking an annual rate increase of some $4,189,000, or approximately 2.1 percent.[6] At the same time, DEA also requested that the Commission establish an interim rate increase of approximately $3 million, or 1.5 percent, effective September 11, 2014, beginning with DEA's October 2014 Cycle 1 billing, which reflected consumption beginning on and after September 11, 2014.[7]

7. The only party to file comments was the Department, which recommended accepting the filing as complete and referring the case for contested case proceedings.

8. On August 29, 2014, the Commission issued three orders in this matter. The first order accepted the filing and suspended the proposed rates.[8] The second order set interim rates and required certain notices.[9] The third order was a Notice and Order for Hearing.[10] The Commission properly referred the matter to the Office of Administrative Hearings to conduct a contested case proceeding pursuant to Minnesota Statutes Chapter 14 (2014).

9. A prehearing conference was held on September 9, 2014, in the Large Hearing Room at the Commission's offices in St. Paul, Minnesota.

10. The OAG filed a petition to intervene on September 9, 2014.[11] DEA and the Department, the other parties to the proceeding, agreed at the prehearing conference to the OAG's proposed intervention.[12]

III. SUMMARY OF PUBLIC TESTIMONY

11. The Administrative Law Judge convened two public hearings. The public hearings were held on December 2, 2014 at the Apple Valley Senior Center, 14601 Hayes Road in Apple Valley, Minnesota, at 2:00 p.m., and at the Dakota Energy Association, 4300 220th Street West, in Farmington, Minnesota, at 7:00 p.m.

12. Five individuals signed the hearing register at the public hearing at the Apple Valley Senior Center. Mr. Douglas Larson, DEA's Vice President of Regulatory Services, appeared on behalf of DEA and provided a brief overview of DEA and its rate

[5] Ex. 128 at 3 (Settlement Agreement).
[6] Ex. 100 at 2-3 (Miller Direct).
[7] NOTICE OF COMMENT PERIOD ON COMPLETENESS AND PROCEDURES at 1 (July 7, 2014) (eDocket 20147-101230-02).
[8] ORDER ACCEPTING FILING AND SUSPENDING RATES (August 29, 2014) (eDocket 20148-102659-01).
[9] ORDER SETTING INTERIM RATES (August 29, 2014) (eDocket 20148-102663-01).
[10] NOTICE AND ORDER FOR HEARING (August 29, 2014 (eDocket 20148-102661091).
[11] PETITION TO INTERVENE (September 9, 2014) (eDocket 20149-102944-03).
[12] First Prehearing Conference Transcript at 5 (September 9, 2014).

increase request.[13] Dorothy Morrissey appeared on behalf of the Commission to describe the role of the Commission and its staff in the proceedings.[14] Ron Nelson of the OAG, and Zac Ruzycki of the Department, each offered the attendees a summary of his respective agency's involvement with, and general position regarding, DEA's rate petition.[15]

13. Four individuals commented and asked questions during the Apple Valley public hearing. Ms. Kettle remarked that many people and institutions have been required to economize in the recent past and continue to have to do so. Ms. Kettle stated that she appreciates the good service she receives from DEA, but that she opposes a rate increase.[16]

14. Ms. Marian Brown noted that she has been part of DEA for at least 40 years. She commented that DEA has very few outages compared to what she hears about other electric utilities in the area. Ms. Brown stated that rates for DEA had not increased in some time and reasoned that, with other costs increasing, the cost of electricity might be expected to increase as well.[17] Ms. Brown asked Mr. Larson about DEA's employee numbers. Mr. Larson said DEA employed about 230 people approximately 10 to 15 years ago, but now employs about 200 people. Ms. Brown also asked why DEA was proposing that residential rates increase more than business rates. Mr. Larson provided the group with a brief explanation of DEA's efforts to balance class costs.[18]

15. Mr. Fred Easter asked several questions regarding the relationship between DEA's proposed monthly charge increase and specific expense items, such as raises and travel costs, which the OAG mentioned it was challenging. Mr. Larson, Mr. Nelson, and Mr. Ruzycki each provided clarifying responses.[19] Mr. Easter also asked how an increased customer base and revenue stream would affect DEA's need for a rate increase. Mr. Larson explained that a sales forecast is part of the rate case.

16. Ms. Therese Ryman made several comments about her situation as a disabled person on a fixed income. She requested that DEA take into consideration that disabled people rely on DEA's electric service. Ms. Ryman stated that she appreciates the work that DEA has done to improve the electric service in her neighborhood, but that she is not in a position to pay more for the service.[20]

17. No members of the public attended the 7:00 p.m. public hearing in Farmington.

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[13] Apple Valley Public Hearing Transcript (Apple Valley Tr.) at 12-13 (December 2, 2014).
[14] *Id.* at 14-15.
[15] *Id.* at 16-19.
[16] *Id.* at 20-24.
[17] *Id.* at 24-26.
[18] *Id.* at 40-43.
[19] *Id.* at 26-32.
[20] *Id.* at 33-36.

18. Members of the public submitted a total of seven written comments to the Administrative Law Judge and the Commission combined. Each of the seven individuals who submitted written comments opposed DEA's request for a rate increase.

IV. RESOLVED ISSUES

19. At the commencement of the evidentiary hearing on December 18, 2014, DEA and the Department stated that they had reached agreement on all issues that had previously been disputed between them. A signed Settlement Agreement memorializing the issues resolved between the Department and DEA (Settling Parties) was offered and admitted into evidence at the conclusion of the evidentiary hearing.[21]

20. On January 20, 2015, the Department filed a letter with the Administrative Law Judge requesting admission of an additional exhibit. The exhibit was an Amendment to the Settlement Agreement between the Settling Parties. It reflected corrections to the Department's calculated rate of return on common equity (ROE) of 4.35 percent and the calculations that rely upon that number. The other parties did not object to the Department's request. On February 10, 2015, the Administrative Law Judge issued an Order Granting the Department's Request to Admit Exhibit 128A, the Amendment to the Settlement Agreement.[22]

21. The OAG did not object to the Settling Parties' positions as stated in the Settlement Agreement except where noted otherwise herein.

A. Financial Issues

22. The Settling Parties agreed to the Total Test Year Operating Expenses (excluding interest) of approximately $192,961,000, reflecting a Total Revenue Requirement (including margin) of approximately $203,753,000.[23]

23. The OAG disputed certain operating expenses, which are discussed at Section V.A. below. If the Commission accepts the recommendation of the Administrative Law Judge, the Total Test Year Operating Expenses would be reduced by $329,015.00.[24]

24. DEA reduced its required net operating income and resulting test-year revenue deficiency by including approximately $399,000 of non-operating income consisting of 1) interest on non-operating margins; 2) subsidiary net income; and 3) other revenue from non-operating margins.[25]

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[21] Ex. 128 (Settlement Agreement).
[22] ORDER ON REQUEST TO ADMIT POST-HEARING EXHIBIT (February 11, 2015) (eDocket 20152-107242-01).
[23] Ex. 128 at 4 (Settlement Agreement).
[24] *See* ¶¶ 63 to 68.
[25] Ex. 128 at 5 (Settlement Agreement).

25. In prefiled Direct Testimony, the Department noted that, normally, rate-regulated utilities calculate net operating income and the resulting test year revenue deficiency on a stand-alone basis, which does not include non-utility businesses. Accordingly, the Department recommended, and DEA agreed, that DEA's non-operating income of $399,147 be reduced by $272,889 to $116,258.[26]

26. DEA proposed an adjustment to normalize its December, 2013 depreciation expense for the test year, which increased the test year depreciation expense by $78,749. The Department accepted this adjustment and recommended a corresponding increase in test year accumulated depreciation of $78,749 to reflect the increase in depreciation expense. DEA concurred with the Department's accumulated depreciation recommendation.[27]

27. DEA proposed an adjustment to normalize the percentage of payroll that is expensed, as opposed to capitalized, in the test year. The Department did not oppose DEA's proposed adjustment, but recommended 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, reducing DEA's test year rate base by $228,590. DEA agreed with the Department's recommended adjustment to rate base to reflect the normalization of payroll.[28]

28. Cash working capital is the amount of money DEA must have on hand to pay for the costs it incurs to serve its customers. 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 was added to its test year rate base. The Department noted that DEA's calculation of cash working capital included test year interest expense, which is included in overall rate of return calculations rather than cash working capital. The Department recommended that the test year cash working capital be reduced by $125,290 for the lead/lag study due to various Department adjustments, including the removal of interest expense. DEA concurred with the Department's recommended adjustment to cash working capital.[29]

29. DEA initially proposed a test year rate base of $171,613,635. The Department made a number of adjustments, totaling $432,629, and recommended a rate base of $171,181,006. The resulting overall rate of return, based on calculations and recommendations contained in the prefiled Direct Testimony of Department witness Dr. Amit, as amended by the Amendment to the Settlement Agreement, is 6.47 percent.[30] DEA agreed with the Department's recommended adjustment to rate base and overall rate of return.[31]

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[26] *Id.* at 5.
[27] *Id.* at 6.
[28] *Id.*
[29] Ex. 128 at 7 (Settlement Agreement).
[30] *Id. at* 7; Ex. 128A at 2 (Amendment to the Settlement Agreement).
[31] *Id.*

30. After reflecting all adjustments summarized in the Department's prefiled testimony, and adjusting for the revised cost of equity as reflected in the Amendment to the Settlement Agreement, the Department recommended a revenue deficiency for DEA of $4,358,994.[32] DEA concurred with the Department's recommended revenue requirement in rebuttal testimony.[33]

31. Noting that Minn. Stat. § 216B.16, subd. 5 (2014), prohibits the revenue requirement to exceed the level of rate increase requested by the utility, the Department concluded that DEA supported its proposed overall rate increase.[34] DEA acknowledged in the Settlement Agreement that the annual revenue increase in this proceeding is limited to the amount requested in its initial filing.[35]

B. Capital Structure, Rate of Return, and Return on Equity

32. The Settling Parties agreed on the following principles and outcomes in determining DEA's capital structure, rate of return, and return on equity.

33. Department witness Dr. Amit determined that, because the overall rate of return is applied to the rate base to produce the appropriate level of net income, the overall rate of return must be adjusted to allow DEA to earn the same amount on its rate base as it would on its total capitalization.[36]

34. The Department noted that its recommended return on equity (ROE), cost of debt, and the resulting overall rate of return (ROR) are based on DEA's initially filed test year rate base of $171,613,635 and that, if the Commission approves a different rate base, then the return should be adjusted.[37]

35. Given its specific nature as a cooperative utility, the required return on DEA's equity is not determined by the opportunity cost of investing capital somewhere else. Instead, it is determined by the need to finance the growth of DEA's rate base and maintain a sound capital structure.[38]

36. Unlike an investor-owned utility (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," because 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 returned to DEA's

[32] Ex. 128 at 8 (Settlement Agreement); Ex. 128A at 2 (Amendment to the Settlement Agreement).
[33] Ex. 126 at 5 (Larson Rebuttal).
[34] Ex. 128 at 8 (Settlement Agreement); Ex. 128A at 2 (Amendment to the Settlement Agreement).
[35] Ex. 128 at 8 (Settlement Agreement).
[36] Ex. 300 at 19 (Amit Direct).
[37] *Id.* at 6; Ex. 128 at 9 (Settlement Agreement).
[38] Ex. 300 at 6 (Amit Direct); Ex. 128 at 9 (Settlement Agreement).

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.[39]

37. 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.[40]

38. To meet these financial requirements, the Department estimated a cost of equity for DEA of 4.28 percent.[41]

39. DEA's capital structure, amended to reflect DEA's refinancing of long-term debt in January 2014, is as follows:[42]

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%

40. As applied to total capitalization, the Department recommended an overall rate of return of 4.71 percent; however, as applied to the rate base, the Department recommended an overall rate of return of 6.47 percent. This rate is based on Dr. Amit's recommended rate of return on common equity of 4.28 percent, a cost of debt of 5.31 percent, and overall return on total capital of 4.71 percent. 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) on rate base = 4.71 x Total Capitalization/Approved Rate Base.[43]

41. 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 percent. DEA agreed that the Department's capital structure, ROE, and ROR calculations are reasonable. DEA's

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[39] Ex. 300 at 5 (Amit Direct).
[40] *Id.* at 6-7.
[41] Ex. 128A at 2 (Amendment to the Settlement Agreement).
[42] Ex. 300 at 16 (Amit Direct).
[43] *Id.* at 19; Ex. 128A at 2 (Amendment to the Settlement Agreement).

agreement with the Department's analysis and conclusions is reflected in the parties' Settlement Agreement.[44] The OAG did not object to the recommended capital structure, ROE, or ROR.

42. Based on the adjusted amount of the agreed-upon rate base of $171,181,006 and the corrected ROR calculations as reflected in the Amended Settlement Agreement, the Settling Parties agreed on the following ROR calculations:[45]

	Original	Revised
Equity Cost	4.35%	4.28%
Debt Cost	5.31%	5.31%
Overall Cost of Capital	4.75%	4.71%
Overall Return on Rate Base	6.53%	6.47%
DOC Revenue Deficiency	$4,454,787	$4,358,994

43. The Administrative Law Judge agrees and also finds that all of the parties' recommendations for DEA's capital structure, ROE, and ROR are reasonable.

C. Energy Sales

44. DEA's filing included a weather-normalized energy sales forecast.[46] The Department analyzed and approved DEA's calculations of test year energy sales volumes and customer counts. The Settlement Agreement reflects the Settling Parties' agreement regarding DEA's energy sales volumes and customer counts.[47]

D. Class Cost of Service Study

45. DEA's filing included a class cost of service study (CCOSS) that used the same model approved by the Commission in DEA's 2009 rate case, with two modifications.[48] One modification was the inclusion of a new wholesale power energy charge.[49] The second modification was DEA's use of the minimum-size method to determine the relative amount of specified distribution accounts to classify as customer

[44] Ex. 126 at 4–5 (Larson Rebuttal); Ex. 310 at MAJ-S-6 (Johnson Surrebuttal); Ex. 128 (Settlement Agreement); Ex. 128A (Amendment to the Settlement Agreement).
[45] Ex. 128 at 10 (Settlement Agreement); Ex. 128A at 2 (Amendment to the Settlement Agreement).
[46] Ex. 122, Workpaper 13 (Larson Direct Workpapers).
[47] Ex. 128 at 10 (Settlement Agreement).
[48] *In the Matter of the Application of Dakota Elec. Ass'n for Auth. to Increase Rates for Elec. Serv. in Minn.*, PUC Docket No. E-111/GR-09-175, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 23 (May 24, 2010) (GR-09-175 ORDER).
[49] Ex. 101 at 21 (Larson Direct).

costs.[50] The Department evaluated DEA's CCOSS, concluded it was reasonable, and recommended that the Commission adopt DEA's proposed CCOSS.[51]

46. The OAG did not agree that DEA's proposed CCOSS was reasonable. That issue is addressed at Section V. B. in these Findings.

E. Revenue Apportionment

47. DEA and the Department initially agreed to DEA's proposed revenue apportionment among customer classes, except for the most appropriate revenue apportionment for Small General Service customers.[52]

48. The Settlement Agreement reflects DEA's agreement to the Department's final proposal of a 3.5 percent increase in revenue apportionment for Small General Electric Service customers and a 0.27 percent increase in revenue apportionment for General Service customers.[53]

49. The OAG did not agree with the Settling Parties' agreement regarding revenue apportionment. That issue is addressed at Sections V.C.1. and 2. in these Findings.

F. Rate Design

50. The Department evaluated and approved DEA's proposals regarding several rate design issues, including customer charges, residential time-of-day tariffs, geothermal heat pump, line extension charges, and reconnection charges.[54] However, the Department objected to DEA's $2.00 per month increase in the Residential and Farm class fixed customer charges.[55]

51. The Settlement Agreement reflects DEA's agreement to the Department's proposed Residential and Farm class fixed customer charges, which constitutes a $1.00 increase rather than a $2.00 increase.[56]

52. The OAG disputed any increase in the fixed customer charges for Residential and Farm customers as well as Small General Service customers. Fixed customer charge issues are addressed at Section V.C. 3 in these Findings.

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[50] *Id.* at 21.
[51] Ex. 303 at 8 (Ruzycki Surrebuttal); Ex. 128 at 11 (Settlement Agreement).
[52] Ex. 101 at 39-40 (Larson Direct); Ex. 304 at 7 (Peirce Direct).
[53] Ex. 128 at 23 (Settlement Agreement).
[54] Ex. 304 at 23 (Peirce Direct).
[55] Ex. 107 at 1 (Larson Direct Attachments); Ex. 304 at 23 (Peirce Direct).
[56] Ex. 128 at 14 (Settlement Agreement); Ex. 304 at 23 (Peirce Direct).

G. Matching of Power Cost Revenue and Expense

53. In the Notice and Order for Hearing, the Commission asked the parties "to address and provide schedules and supporting documentation in the development of the record in this matter, to show the matching of power cost revenue to power cost expense in the pro forma test year financial schedules."[57]

54. In response, DEA prepared an updated response to the Department's Information Request 505.[58] First, DEA proposed to revise the Power Cost Adjustment (PCA) base applied to firm service rate schedule, resulting in a net change from $0.0899 per kWh to $0.0903 per kWh.[59] Second, the calculation of tariffed revenue under present and proposed rates and resulting identification of tariffed revenue associated with wholesale power service from GRE and distribution services includes a component recognizing approximately $285,000 in the current cost of power for various carry-over/true-up amounts in DEA's present Resource and Tax Adjustment (RTA).[60] These amounts will be trued-up as DEA's RTA transitions from present rates to proposed rates.[61] Together, these updates result in the calculated tariff revenue associated with wholesale power nearly equaling the wholesale power costs included in the test year.[62]

55. The Settlement Agreement reflects the Settling Parties' belief that DEA has properly demonstrated the matching of wholesale power cost revenue and expense.[63]

V. DISPUTED ISSUES

A. Financial Issues

1. Travel and Miscellaneous Expenses

56. DEA requested recovery of business expenses stemming from travel and meals for its employees, as well as food and event expenses for its Board of Directors.

57. If a utility seeks to recover travel and miscellaneous employee expenses, the expenses must be itemized and requested as part of the initial filing in a rate case.[64] Under Minnesota law, a utility is required to separately itemize the following: travel and lodging expenses; food and beverage expenses; recreational and entertainment expenses; board of director-related expenses; dues for memberships in organizations

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[57] NOTICE AND ORDER FOR HEARING at 2 (August 29, 2014).
[58] Ex. 127 at 19 (Larson Surrebuttal).
[59] *Id.*
[60] *Id.*
[61] *Id.*
[62] *Id.*
[63] Ex. 128 at 15 (Settlement Agreement).
[64] Minn. Stat. § 216B.16, subd. 17(a).

and clubs; and gift expenses.[65] These expenses are recoverable "only to the extent that the activities they support directly benefit ratepayers."[66] The Commission "may not allow" a utility to recover "travel, entertainment, and related employee expenses" that are "unreasonable and unnecessary for the provision of utility service."[67]

58. In this case, the OAG disputed a portion of DEA's requested recovery of travel and miscellaneous employee expenses. Specifically, the OAG claimed the following expenses are unreasonable and not necessary for DEA's provision of utility service:

a) $2,066 in travel reimbursements for a DEA Board member to attend multiple Cooperative Finance Corporation (CFC) meetings.[68] The OAG pointed out that the meetings were "held outside DEA's service territory" and claimed attendance was not directly related to DEA's provision of electric service.[69]

b) $672 in airfare costs for scheduling a DEA Board member's trip to attend a meeting in Washington, DC.[70] The OAG argued that "it is imprudent for DEA's ratepayers to pay for the high cost of a flight that the company failed to schedule until the last minute."[71] However, the OAG does not dispute the legitimacy of someone from DEA attending the meeting in Washington, D.C.[72]

c) $3,909 in groceries served to DEA employees and board members at various company functions.[73] The OAG asserted that DEA has failed to demonstrate "ratepayers directly benefit from providing food and other perks [to employees] at company meetings and functions."[74]

d) $522 for a holiday luncheon for DEA's Board members and employees.[75] The OAG argued provision of a "holiday" luncheon should not be recoverable from ratepayers.[76]

e) $3,141 for a retirement party for DEA's attorney.[77]

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[65] *Id.*
[66] *In the Matter of the Application of Interstate Power Co. for Auth. to Increase its Rates for Elec. Serv. in the State of Minn.*, Docket E-001/GR-91-605, 1991 WL 634712, at *3 (Minn. P.U.C. Oct. 11, 1991); *see also* Minn. Stat. § 216B.17(a)(6) (2014).
[67] Minn. Stat. § 216B.16, subd. 17(a).
[68] Ex. 203 at 12 (Lee Direct).
[69] OAG Initial Post-Hearing Brief (OAG Initial Br.) at 9.
[70] Ex. 203 at 13 (Lee Direct).
[71] OAG Initial Br. at 11.
[72] Evidentiary Hearing Transcript (Tr.) at 120 (Lee).
[73] Ex. 205 at 12 (Lee Surrebuttal).
[74] OAG Initial Br. at 11.
[75] Ex. 205 at 13 (Lee Surrebuttal).
[76] OAG Initial Br. at 10.

59. DEA conceded the $3,141 expense for the retirement party should be removed from its request because the expense "is not likely to be a recurring expense."[78]

60. DEA asserted, however, that all of the other business expenses challenged by the OAG are legitimate and recoverable:

a) $2,066 expense for travel and meals was incurred when DEA's Director attended regional meetings of electric cooperatives in Minnesota and the Dakotas while he was running for election to the CFC Board of Directors.[79] DEA argued that "[p]otential participation on the board of directors of a major Dakota Electric lender has significant value" because the CFC board "may help design lending policies directly related to the provision of electric service."[80]

b) $672 expense for airfare purchased a few days prior to the event. According to DEA, "[w]hen we determined that DEA did not have anyone attending this conference[,] the arrangements were made only days before the event."[81] Although the last-minute arrangement increased the cost of the airfare, DEA claimed "the expense was justified due to the importance of attending the conference."[82] Moreover, the DEA asserted "in another year, this same expense could have been incurred for two people to attend the conference."[83]

c) $3,909 expense for food and drink items from Family Fresh Market, Sam's Club, and Farmington Bakery.[84] DEA claimed "there is no dispute that these expenses were all incurred at legitimate company and department functions and meetings," and argued "[m]anagement certainly has the prerogative of providing food and beverages at meetings to keep employees refreshed, alert, and productive."[85]

d) $522 expense for food and drink provided to 29 people during the December meeting for DEA's Board of Directors.[86] DEA asserted that "despite the 'holiday' label, this December lunch was no

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[77] Ex. 203 at 12-13 (Lee Direct).
[78] Ex. 126 at 17 (Larson Rebuttal).
[79] Ex. 126 at 16-17 (Larson Rebuttal).
[80] DEA Initial Post-Hearing Brief (DEA Initial Br.) at 2-3.
[81] Ex. 126 at 17 (Larson Rebuttal).
[82] DEA Initial Br. at 3.
[83] Ex. 126 at 17 (Larson Rebuttal).
[84] Ex. 205, SL-15 at 8-9 (Lee Surrebuttal).
[85] DEA Initial Br. at 3.
[86] Ex. 205, SL-15 at 9 (Lee Surrebuttal).

different from other monthly lunch breaks that the Board of Directors takes during its regular meetings."[87]

61. The Administrative Law Judge concludes that DEA has provided sufficient evidence, including itemized information, to show the business expenses objected to by the OAG were incurred as legitimate costs of doing the administrative business necessary for DEA to provide electric service. Specifically:

a) The Administrative Law Judge agrees that DEA's efforts to foster a closer relationship between its Board of Directors and the board of a major lender such as CFC is related to DEA's provision of electric service, and has the potential to benefit DEA's members. Thus, the $2,066 expense for travel and meals incurred when DEA's Director attended regional meetings of electric cooperatives in Minnesota and the Dakotas while he was running for election to the CFC Board of Directors is legitimate and recoverable.

b) The Administrative Law Judge concludes that DEA had a reasonable basis to purchase a premium airfare for its Board member to attend an important conference related to the provision of electric service. According to DEA, the premium airfare was purchased "[w]hen we determined that DEA did not have anyone attending this conference[,] the arrangements were made to have a DEA employee attend the event."[88] Notably, the OAG did not dispute that the DEA representative's attendance at the conference was reasonable and necessary for the provision of electric service.[89] Therefore, the $672 expense for airfare purchased a few days prior to the conference in Washington, D.C. is legitimate and recoverable.

c) DEA withdrew the one non-business related food expense from its initial request: the social gathering in honor of its attorney's retirement. Otherwise, the OAG does not object to the basis for all of the other food expenses included as business expenses in DEA's request for recovery. With regard to the $680 portion of groceries used for DEA's wellness program, the OAG conceded that participation in a wellness program leading to a reduction in health insurance premiums is related to DEA's provision of electric service.[90] Therefore, the $3,909 expense for food and drink items from Family Fresh Market, Sam's Club, and Farmington Bakery is reasonable and recoverable.

d) The Administrative Law Judge concludes that DEA's expense for a "holiday luncheon" was reasonable because the $522 was spent on

[87] DEA Initial Br. at 3.
[88] Ex. 126 at 17 (Larson Rebuttal).
[89] Tr. at 120 (Lee).
[90] *Id.* at 122.

lunch for 29 people during the regular December DEA Board of Directors meeting.[91] Therefore, the Administrative Law Judge recommends that the $522 expense for DEA's December Board luncheon be recoverable.

62. Based on the foregoing reasoning, the Administrative Law Judge recommends DEA's request for business expenses stemming from travel and meals for its employees, as well as food and event expenses for its Board of Directors, be included in the test year for rate recovery, minus the $3,141 expense for the retirement party.

2. Adjustment for Staffing Changes

63. DEA requested recovery of increased costs in payroll expenses, including an annualization adjustment covering 16 employee positions vacant for a portion of the test year (2013), as well as the addition of one new employee position in 2014.[92] According to DEA, it paid out $643,269 in actual wages for the 16 partially filled positions in 2013 instead of $1,040,494 in wages that would have been paid if the positions had all been filled for the entire year.[93] DEA also added one new position (Powerline Design Technician) in 2014, which has an annual wage of $68,210.[94] Based on the new additional position and total wages necessary to fully fund the 16 positions for an entire year, DEA requested an increased annualization adjustment of $465,435.[95]

64. The OAG, however, valued DEA's annualization adjustment at $690,427 based on the wages claimed by DEA plus the OAG's calculation of the benefit expense for the 16 partially filled positions ($589,244) and one new added position ($101,183).[96] The OAG objected to DEA's annualization adjustment for two reasons.[97] First, the OAG claimed DEA failed to show the increase is "a known and measurable change"[98] because DEA's request covers positions "it hopes to fill or to remain filled, rather than positions . . . it knows will be filled."[99] The OAG claimed the additional "incremental position" for a new Powerline Design Technician "appears to inflate compensation expenses."[100] Second, the OAG argued the requested increase cannot be reconciled with the general trend of DEA's payroll expense, which has been relatively flat for the past three years.[101] Between 2010 and 2013, the OAG claimed the average change in

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[91] Ex. 205, SL-15 at 9 (Lee Surrebuttal).
[92] Ex. 102 at 5 (Larson Direct Attachments).
[93] *Id.*
[94] Ex. 126 at 13 (Larson Rebuttal); Ex. 102 at 5 (Larson Direct Attachments).
[95] Ex. 102 at 5 (Larson Direct Attachments).
[96] Ex. 203 at 6 (Lee Direct); Tr. at 134 (Lee).
[97] OAG Initial Br. at 4.
[98] *Id.* at 6.
[99] *Id.*
[100] Ex. 203 at 7 (Lee Direct).
[101] OAG Initial Br. at 6.

DEA's annual payroll expense has been less than one percent as detailed in the table below:[102]

Year	Expensed Payroll	$ change over (under)	% change over (under)
2010 actual	$14,069,983		
2011 actual	$14,068,038	($1,945)	(0.01%)
2012 actual	$14,030,172	($37,866)	(0.27%)
2013 actual	$14,093,131	$62,959	0.45%
Average of 2010-2013	$14,065,331		0.06%

65. Based on the OAG's calculation, granting DEA a $690,427 annualization adjustment would result in more than a four percent increase in expensed payroll for 2014.[103] Thus, the OAG claimed "the fact that [DEA's] payroll expense during its 2013 test year was higher than any of the previous years, despite several unique circumstances described by Mr. Larson, confirms [the requested increase] is both unnecessary and excessive."[104]

66. In response, DEA argued the annualization adjustment increase "recognizes the existing level of staffing that *should* be included in the test year and recovered through rates."[105] According to DEA, "the positions identified for the annualization compensation adjustment are existing positions that are filled or in the process of being filled"[106] and "disallowing the annualization adjustment [would have] the net effect of removing from rate recovery the compensation and benefits of six existing Dakota Electric positions."[107] DEA claimed "2013 was an atypical year" that distorted "the job vacancy data beyond the normal employee turnover."[108] Moreover, DEA argued that "[t]he OAG's four year average payroll is outdated information" and should not be considered.[109]

67. The Administrative Law Judge concludes that the underlying basis for the OAG's objection to DEA's annualization adjustment has merit. Historically, test year methodology "rests on the assumption that changes in [a] [c]ompany's financial status during the test year will be roughly symmetrical – some favoring [a] [c]ompany, others not . . . . Anomalies are likely to exist in and beyond the test year."[110] Whether or not specific positions are fully filled during a test year does not warrant extra funding to cover the likelihood that all positions will be filled the following year. Each year brings

[102] Ex. 203 at 6 (Lee Direct).
[103] *Id.* at 7.
[104] OAG Initial Br. at 7.
[105] DEA Initial Br. at 4.
[106] Ex. 126 at 13 (Larson Rebuttal).
[107] DEA Initial Br. at 4.
[108] *Id.*
[109] *Id.*
[110] *In the Matter of the Application of N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, PUC Docket No. E-002/GR-05-1428, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 10 (Sept. 1, 2006).

turnover and circumstantial situations affecting a company's ability to keep positions filled. In the end, staffing changes will work themselves into the symmetry contemplated by the economics behind the test year methodology. Thus, the annualization adjustment requested by DEA in this case is not necessary.

68. However, the OAG's proffered exclusion of $690,427 for the annualization adjustment is inconsistent with the amount requested by DEA. According to DEA witness Douglas Larson, DEA is seeking an annualization adjustment of $397,225 for 16 partially filled positions[111] plus $68,210 for a new position added in 2014.[112] The Administrative Law Judge recommends granting DEA's request for an increase of $68,210 to cover additional wages for the new added position in 2014, but disallowance of the increase of $397,225 to adjust for partial staffing in 2013, for a net disallowance of $329,015.

3. Support Hours Formerly Provided to EAI

69. The OAG requested a downward adjustment to DEA's overall payroll expense based upon employee support service hours no longer being billed to Energy Alternatives Parent, Inc. (EAI), a non-regulated subsidiary of DEA.[113] Specifically, the OAG recommended that the additional labor capacity resulting from the decreased employee work hours provided and charged to EAI be applied as an offset to DEA's requested rate increase.[114]

70. In 2010, DEA billed 1,197 employee work hours to EAI for finance, billing, and administrative services provided by DEA employees for EAI operations.[115] In 2013, the test year for this case, DEA billed 355 employee work hours to EAI,[116] a significant decrease following EAI's divestiture of interests in leasing and wholesale generation businesses.[117] Thus, the OAG theorized that, between 2010 and 2013, DEA gained 872 employee work hours for its operations because of the hours no longer being provided and charged to EAI.[118]

71. The OAG objected that "DEA has not claimed these 21 weeks [or 872 hours] of additional labor capacity are needed to perform its regulated functions in 2013" and has "failed to make an adjustment to its 2013 test year to eliminate these unnecessary costs."[119] The OAG highlighted the $57,700 cost of the 872 work hours[120]

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[111] Ex. 102 at 5 (Larson Direct Attachments).
[112] Ex. 126 at 13 (Larson Rebuttal); Ex. 102 at 5 (Larson Direct Attachments).
[113] OAG Initial Br. at 8-9.
[114] *Id.* at 9.
[115] Ex. 203, SL-7 at 1 (Lee Direct).
[116] *Id.*
[117] Ex. 203 at 8 (Lee Direct).
[118] Ex. 205 at 8 (Lee Surrebuttal).
[119] OAG Initial Br. at 8.
[120] Tr. at 39-40 (Larson).

and claimed "it is unreasonable for ratepayers to pay for all of these extra hours of labor that the company does not claim are needed to operate the regulated utility service."[121]

72. DEA responded that the additional work hours have been absorbed by the day-to-day operations of running its utility service, and do not result in any direct cost savings.[122] According to DEA, changes have been made to the responsibilities of various employees who previously provided and billed work hours to EAI.[123] Moreover, 21 of the 23 employees who billed EAI for work hours in 2010 are salaried employees, including DEA's CEO, Vice President of Finance, and the Corporate Controller.[124] These employees often work more than a 40-hour week but are not compensated beyond their set salaries.[125] Thus, DEA argued that a reduction to test year expenses for hours no longer billed to EAI is not warranted.[126]

73. OAG replied that "DEA's argument ignores the fact that, by no longer charging these hours to EAI, DEA is requesting that they be paid by ratepayers," but "has not identified any benefit [being received] for these additional costs."[127]

74. The Administrative Law Judge concludes that the OAG's request for a downward adjustment to DEA's overall payroll expense based upon employee support service hours no longer being provided and billed to EAI lacks merit. There is no evidence that the 842 work hours previously provided and billed to EAI by DEA employees are not being fully utilized. On the contrary, DEA's testimony is that it is fully utilizing those employees' hours. More importantly, 21 of the 23 employees who billed EAI for work hours in 2010 are salaried employees, including DEA's CEO, Vice President of Finance, and the Corporate Controller.[128] The salaries of these employees have been included within DEA's operating expenses from 2010 through 2013. Therefore, a reduction to DEA's requested rate increase is not warranted.

B. Class Cost of Service Study

1. Background

75. The purpose of a Class Cost of Service Study (CCOSS) is to identify, as accurately as practicable, the responsibility of each customer class for the costs incurred by the utility to provide service for that class.[129] A CCOSS assigns costs to each customer group that imposes costs on the system. The process should provide for the equitable allocation of costs among all customer classes in a manner that most

[121] *Id.*
[122] DEA Initial Br. at 5
[123] Tr. at 41 (Larson).
[124] Tr. at 40-41 (Larson).
[125] *Id.* 41.
[126] DEA Initial Br. at 5.
[127] OAG Initial Br. at 9.
[128] Tr. at 40-41 (Larson).
[129] Ex. 301 at 3 (Ruzycki Direct).

accurately represents the true nature of the factors that cause the costs to be incurred (cost causation).[130]

76. The CCOSS plays an important role in determining how costs should reasonably be recovered from the different customer classes through rate design.[131]

77. A CCOSS is comprised of three main steps: (1) functionalization, which groups costs based on their purpose; (2) classification, which refines the functionalized costs by identifying the utility operation on which the costs are spent; and (3) allocation, which assigns costs to customer classes based on the cost impact each class imposes on the system.[132]

78. Costs that have been functionalized and classified, and that can be identified as logically incurred to serve a particular class of customer are allocated to the customer classes based on the following criteria: (1) customer-related costs – costs allocated based on the number of customers in the class, generally weighted to reflect differences in metering costs among classes; (2) demand-related costs – costs allocated based on the energy demanded of the system to serve the customer class, using peak responsibility and demand factors to allocate costs such as transmission, distribution, and generation demand-related costs; and (3) energy-related costs – costs allocated based on the energy the system must supply to serve the customer class.[133]

79. Generally, costs are functionalized by the Uniform System of Accounts as provided by the Federal Energy Regulatory Commission (FERC). The utility's total revenue requirement is divided, using the functionalization categorization system, into functional components related to the utility's operations, such as Generation, Transmission, Distribution, and General Plant.[134]

80. For DEA, the largest portion of costs to serve members is in essence a pass-through of demand and energy charges that are billed by DEA's wholesale power supplier, GRE. Distribution costs are only about 26 percent of DEA's total CCOSS costs.[135]

81. For its CCOSS, DEA used a methodology referred to as a "fully allocated averaged embedded" approach. This approach means that: (1) costs are allocated on an average system-wide basis; and (2) embedded or accounting costs, as recorded on DEA's books, are used in the analysis.

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[130] *Id.*
[131] Ex. 303 at 2 (Ruzycki Surrebuttal); Ex. 304 at 1 (Peirce Direct).
[132] Ex. 301 at 4 (Ruzycki Direct).
[133] *Id.* at 5-6.
[134] *Id.* at 4.
[135] Ex. 104, DEA-3 at 2 (Larson Direct Attachments).

82. DEA used the same methodology that the Commission approved in DEA's last rate case with the exception of two changes.[136] First, DEA implemented a minimum-size methodology to complete a minimum-system study necessary to classify specific distribution accounts. Historically, DEA has always used a zero-intercept method to complete its minimum-system study.[137] However, in DEA's last rate case, the Commission required DEA to complete a minimum-system study for this rate case by using the minimum-size method. The Commission specifically provided:

> 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.[138]

83. Second, DEA allocated new ancillary service energy costs to customer classes based on kWh purchases and the ancillary services rate. Ancillary service costs are the transaction costs associated with participation in the Midcontinent Independent System Operator's (MISO) Ancillary Services Market (ASM). ASM charges are associated with buying and selling various secondary services necessary to support capacity and transmission of energy.[139]

84. The Department agreed that both of the modifications DEA made to its CCOSS are reasonable.[140]

85. The Department also agreed that: DEA's classification and allocation of the functionalized accounts are generally consistent with the National Association of Regulatory Utility Commissioners (NARUC) Electric Manual; DEA has made relevant updates to its input data in calculating the CCOSS; and DEA used reasonably current data in its CCOSS.[141]

2. Minimum-System Study Background

86. There is one issue concerning the CCOSS that was disputed by the OAG. That issue is the most appropriate minimum-system study for purposes of determining distribution costs. The OAG did not agree with the Department and DEA that DEA's minimum-size method analysis provides a reasonable basis for determining distribution costs.[142] Instead, the OAG proposed a "zero-intercept proxy" method as an alternative to DEA's minimum-size method.[143]

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[136] Ex. 301 at 6 (Ruzycki Direct).
[137] Ex. 125, Workpaper 21 at 1 (Larson Direct Workpapers).
[138] Ex. 301 at 7 (Ruzycki Direct); GR-09-175 ORDER at 23.
[139] Ex. 301 at 12 (Ruzycki Direct).
[140] *Id.*
[141] Ex. 301 at 13–14 (Ruzycki Direct). The OAG did not specifically comment on these aspects of the CCOSS.
[142] *See generally* Ex. 200 (Nelson Direct), Ex. 201 (Nelson Rebuttal), Ex. 202 (Nelson Surrebuttal).
[143] Ex. 200 at 20 (Nelson Direct).

87. The NARUC Electric Manual describes the purpose of the minimum-system study and alternative approaches to doing the study as follows:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.
>
> Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.
>
> ....
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> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services and meters are directly related to the number of customers on the utility's system. As shown . . . each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.[144]

88. The minimum-size method requires the utility first to determine the minimum size pole, conductor, cable, transformer, and service currently installed by that utility. The analyst must choose among 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. The average book cost for each identified piece of equipment determines the price of all installed units. These costs are established for each primary plant account, and allocated according to the number of customers per rate-class. Costs beyond those classified as customer-related this way are classified as demand-related.[145]

89. 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.[146]

[144] Ex. 311 at 90 (NARUC Electric Utility Cost Allocation Manual).
[145] *Id.* at 90-92; Ex. 301 at 8, 10 (Ruzycki Direct).
[146] Ex. 301 at 9 (Ruzycki Direct).

90. 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-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.[147]

91. 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.[148]

3. DEA Minimum-Size Method Analysis

92. DEA chose the following 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), based on the minimum sizes on DEA's system. Those minimum sizes are:

- 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.[149]

93. DEA calculated that the weighted average minimum-size consumer classification for its Distribution Accounts 364, 365, 367 and 368 is 61.5 percent of total distribution costs.[150]

94. DEA compared its minimum-size method results with a hypothetical zero-intercept method analysis. To perform this analysis, DEA first multiplied the installed book cost of each of the distribution accounts in its minimum-size method in the current rate case by the customer percentage from its 2009 zero-intercept method. Next, DEA

[147] *Id.* at 10; Ex. 311 at 92 (NARUC Electric Utility Cost Allocation Manual).
[148] Ex. 301 at 9 (Ruzycki Direct).
[149] Ex. 125, Workpaper 21 at 3-4 (Larson Direct Workpapers).
[150] *Id.* at 4.

calculated the zero-intercept percentage for this case based on the current rate case costs and the 2009 zero-intercept percentage. This calculation resulted in a 57.1 percent weighted zero-intercept percentage compared to DEA's 61.5 percentage based on its minimum-size method in this docket.[151]

95. DEA also prepared the following chart comparing the CCOSS results using the minimum-size method and the zero-intercept method percentages it calculated as described above:[152]

Method	Resid&Farm	Sm.Gen'l.Svc.	Irrig.	Gen'l. Svc.	C&I Interrupt.	Lighting
Minimum-size	2.85%	7.47%	2.03%	-0.33%	2.33%	1.12%
Zero-intercept	2.94%	7.60%	1.17%	-0.46%	2.17%	1.14%

96. Based on the similarity of the results between its current minimum-size method and the comparison zero-intercept method, DEA concluded that its minimum-size method numbers were reasonable and that a demand adjustment was not needed to its minimum system study.[153]

97. The Department reviewed DEA's minimum-size method analysis and confirmed that DEA chose to use the smallest size equipment in service that would be necessary to serve customer load.[154] The Department further 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

[151] *Id.* at 5; Tr. at 27-33, 66-67 (Larson)

[152] Ex. 125, Workpaper 21 at 4-5 (Larson Direct Workpapers); Tr. at 56 (Larson). DEA claims the anomaly of the minimum-size method resulting in a lower percentage assigned to Residential and Farm customers than the zero-intercept method is because DEA applied the 2009 zero-intercept weighted average to each of the distribution accounts. When the OAG applied the newly-created "hypothetical zero-intercept" of 57.1 percent to the distribution accounts, the Residential and Farm customers were assigned a higher CCOSS percentage. *See* Ex. 200 at 14-15 (Nelson Direct); Ex. 126 at 25-26 (Larson Rebuttal).

[153] Tr. at 56 (Larson). The OAG described a demand adjustment as "a separate adjustment to a demand allocator to acknowledge that the residential class is over allocated demand costs." Ex. 201 at 4 (Nelson Rebuttal). Such an adjustment was accepted by the Commission when presented by CenterPoint Energy in 2013. *See In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minn. Gas for Auth. to Increase Natural Gas Rates in Minn.,* PUC Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at 121, 125 (April 9, 2014) (GR-13-316 RECOMMENDATIONS); *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minn. Gas for Auth. to Increase Natural Gas Rates in Minn.,* PUC Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 36-38 (June 9, 2014) (GR-13-316 ORDER).

[154] Ex. 301 at 11 (Ruzycki Direct).

equipment needed to allow customers to receive service.[155] The Department recommended that the Commission adopt DEA's proposed CCOSS.[156]

4. The OAG's Objections to the Minimum Size Method and Proposed Alternative

98. The OAG generally disfavors the use of the minimum-size method based on its view that the minimum-size method "overestimates customer costs because incremental increases in equipment size or load capability are linked to demand rather than customer costs."[157]

99. In this proceeding, the OAG did not conduct its own minimum-size method analysis for the minimum system study. The OAG asserted that the zero-intercept method is preferable to the minimum-size method, stating the zero-intercept method is "theoretically more accurate" than the minimum-size method "because it recognizes that materials costs vary with demand."[158] However, the OAG chose not to use the zero-intercept method because the OAG's analyst had "never seen [the zero-intercept method] done correctly from a statistics/econometric standpoint."[159]

100. The Department agreed with the OAG that, in a perfect world, with perfect data availability, the zero-intercept method would more closely approximate a theoretical zero-sized system than the minimum-size method does. However, there is not perfect data availability. As a result, the minimum-size method is widely used in CCOSSs. The Department noted that, in this proceeding, the two methods produced similar results: approximately 60 percent of the distribution costs are customer related. The Department contended that DEA's minimum-size method used real costs from DEA's actual system to estimate the costs to build a minimum system necessary to allow customers to take service.[160]

101. The OAG disagreed with DEA and the Department, and perceived inadequacies in both the minimum-size and zero-intercept methodologies. Therefore, the OAG recommended that the Commission adopt a new methodology, developed by OAG witness Ron Nelson, to determine the customer- and demand-related costs in the CCOSS for distribution plant accounts.[161]

102. The OAG proposed an alternative method for classifying distribution plant costs in a CCOSS, called the "zero-intercept proxy." The OAG described the "zero-intercept proxy" as follows:

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[155] *Id.*
[156] Ex. 301 at 15 (Ruzycki Direct).
[157] Ex. 200 at 6 (Nelson Direct).
[158] *Id.* at 7.
[159] Tr. 107 (Nelson).
[160] Ex. 302 at 4–5 (Ruzycki Rebuttal).
[161] *Id.* at 1.

> [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 [it] use[s] 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.[162]

103. The OAG stated that "subtracting the material cost from the installed cost is equivalent to obtaining the zero-intercept estimation." The OAG's zero-intercept proxy classifies 38.3 percent of distribution plant as customer costs. The OAG stated that the "majority of the reason" why the OAG's zero-intercept calculation of 38.3 percent is substantially lower than DEA's own zero-intercept calculation of 57.1 percent is that, under the zero-intercept proxy, all material costs are subtracted from DEA's distribution system.[163]

104. The OAG acknowledged that the zero-intercept proxy model of the minimum system would not be able to deliver capacity or any energy or service to customers of DEA.[164]

105. Because the OAG's zero-intercept proxy method does not reasonably reflect the costs of a system that is capable of delivering power to customers, the Department concluded that the proposed zero-intercept proxy is not a reasonable method of separating DEA's estimated costs of capability of delivering power from its estimated distribution costs of meeting customer demand for power. The Department explained that the OAG's method considers only the costs **of installing** a minimum size pole, but fails to include the equipment costs even of the smallest size pole that would need to be installed, or any other equipment needed to deliver power to DEA's customers. In addition, the Department noted that the OAG's method is at odds with the NARUC Electric Manual, which directs an analyst to consider minimum material costs when conducting a zero-intercept study.[165]

106. The Department affirmed that DEA's minimum-size method is consistent with the NARUC Electric Manual and with the Commission's Order in GR-09-175.[166]

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[162] Ex. 200 at 20 (Nelson Direct).
[163] *Id.* at 20, 24; Tr. at 90 (Nelson).
[164] Tr. at 99-100 (Nelson).
[165] Ex. 302 at 6 (Ruzycki Rebuttal); Tr. at 96, 99–100 (Nelson); Ex. 311 at 92–93 (NARUC Electric Utility Cost Allocation Manual).
[166] Ex. 303 at 3, 5 (Ruzycki Surrebuttal); Ex. 311 at 95 (NARUC Electric Utility Cost Allocation Manual).

5. Demand Adjustment

107. The OAG also recommended that, if the Commission accepts DEA's minimum-size study, the Commission should require that DEA include a demand adjustment to account for possible inclusion in the minimum-size study of demand costs in customer classification.[167]

108. DEA disagreed and argued that a demand adjustment is not necessary in this case for two reasons. First, DEA asserted that its zero-intercept analysis reasonably estimates the proportion of identified plant accounts for customer classification for a system with no load carrying capability, and the zero-intercept's weighted average benchmark comparison validates the minimum-size method results.[168] Second, DEA argued that the nature of its minimum-size method analysis already incorporated irregularities that would compensate for a tendency of the minimum-size method to inappropriately allocate demand capacity costs to customers:

> The average book cost reflects the cost of plant installed 30 to 40 years ago up to the present day. For a particular piece of plant, the majority of such plant could have been installed years ago or more recently. Accordingly, the minimum-size plant could reflect an unusually low cost (if the majority of plant was installed years ago) or it could reflect an unusually high cost (if the majority of plant was installed more recently).[169]

109. The Department agreed with the OAG that, because the minimum-size method can intrinsically include some demand-related costs, a demand adjustment can be appropriate in certain circumstances.[170] However, the Department theorized that such an adjustment could be especially difficult to make in an electric utility case because the amount of load (electricity) flowing through the distribution system is not as easily calculated as a discrete amount of gas.[171] In addition, in this matter, the Department noted that DEA's proposed customer charge is significantly below cost. Therefore, the Department did not support requiring a demand adjustment in this proceeding.[172]

110. The Department suggested that, if the Commission chooses to require DEA to use the minimum-size method in its next rate case, a demand adjustment would be a reasonable accompanying refinement.[173]

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[167] Ex. 201 at 4 (Nelson Rebuttal). See footnote 153 for discussion of the demand adjustment method.
[168] Ex.127 at 12-13 (Larson Surrebuttal).
[169] *Id.* at 13.
[170] Ex. 303 at 7 (Ruzycki Surrebuttal).
[171] *Id.*
[172] Ex. 303 at 8 (Ruzycki Surrebuttal).
[173] *Id.*

6. CCOSS Recommendations

111. The Administrative Law Judge finds that DEA's minimum-size method for classifying distribution plant accounts is reasonably accurate, and reflects real-world minimum-size equipment needed to serve customer load on DEA's system.[174] The Administrative Law Judge respectfully recommends that the Commission accept DEA's proposed CCOSS, including the minimum-size method.[175]

112. In addition, the Administrative Law Judge recommends that the Commission require DEA to conduct its minimum system study in its next rate case by using the minimum–size method, supported by the zero-intercept method.

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

C. Rate Design - Revenue Apportionment

1. Background

114. In the absence of competition, government regulation of utilities' rates 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 a quasi-judicial and fact intensive process. The second step, designing the structure that will determine the rates charged to customers, is largely a quasi-legislative function. While the second step of rate making largely involves facts, it also involves policy decisions.[176]

115. Regulated public utilities can only charge just and reasonable rates.[177] The Commission has relied on the following principles in designing reasonable and just rates:

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

(b) Rates should promote efficient use of resources by sending appropriate price signals to customers, reflecting the costs of

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[174] Ex. 301 at 11, 15 (Ruzycki Direct).
[175] *See* Ex. 104, DEA-3 (Larson Direct Attachments).
[176] *See In the Matter of Request of Interstate Power Co. for Auth. to Change Rates*, 559 N.W.2d 130, 133 (Minn. Ct. App. 1997), *aff'd* 574 N.W.2d 408 (Minn. 1998).
[177] Minn. Stat. § 216B.03 (2014).

serving them. For example, an appropriate price signal encourages conservation by customers;

(c) 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

(d) Rates should be understandable and easy to administer. Maintaining ease in administration helps ensure that customers understand their utility bills better.[178]

The burden is on the public utility to show that its requested rate change is just and reasonable.[179] If there is any doubt as to the reasonableness of a particular rate design, such doubt must be resolved in the customer's favor.[180]

116. Minnesota law encourages rate designs that promote the use of renewable energy.[181] Rates must also encourage energy conservation "to the maximum reasonable extent."[182] 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.[183]

117. In addition, Minnesota law 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.[184]

118. Nor shall a public utility "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."[185] The Commission is also required to consider the ability to pay as a factor when setting public utility rates.[186]

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[178] Ex. 304 at 2 (Peirce Direct).
[179] Minn. Stat. § 216B.16, subd. 4 (2014).
[180] Minn. Stat. § 216B.03.
[181] Minn. Stat. § 216C.05 (2014).
[182] Minn. Stat. § 216B.03.
[183] Minn. Stat. § 216C.05.
[184] Minn. Stat. § 216B.03.
[185] Minn. Stat. § 216B.07 (2014).
[186] Minn. Stat. § 216B.16, subd. 15 (2014); Ex. 304 at 4 (Peirce Direct).

119. Because DEA's rates differ among the various classes of service, the Department asserted 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.[187]

2. Apportionment of Revenue Responsibility

120. The first step in rate design is apportionment of the approved revenue requirement among the customer classes. DEA's initial proposed revenue apportionment was based on the results of its CCOSS, along with other rate design objectives, including the need to avoid abrupt changes and the DEA's desire to achieve member-customer acceptance.[188]

121. DEA's initial proposed revenue apportionment would have increased the Small General Service class by 5.08 percent, and the General Service class by .06 percent.[189]

122. The Department agreed with DEA's proposed revenue apportionment, with two exceptions. In its direct testimony, the Department recommended a lesser 3 percent annual increase for the Small General Service class by increasing the revenue responsibility for the General Service class to 0.34 percent.[190]

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.[191]

124. In response to DEA's concern in that regard, the Department ultimately increased its recommendation for revenues apportioned to the Small General Service class to 3.5 percent. The Department maintained this apportionment would not unreasonably burden other classes. According to DEA's rate schedules, the Department's revised revenue apportionment would result in an approximately $0.60 per month bill impact per Small General Service class customer. With the 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.[192] In addition, the Department recommended a slight increase in the revenue responsibility for General Service class customers, to a 0.27 percent increase.[193]

125. The Department and DEA agreed on these revenue apportionments for the Small General Service and General Service classes. In their January 18, 2015

[187] Ex. 304 at 4 (Peirce Direct).
[188] Ex. 101 at 39-40 (Larson Direct).
[189] *Id.*
[190] Ex. 304 at 7 (Peirce Direct); Ex. 128 at 12 (Settlement Agreement).
[191] Ex. 126 at 8 (Larson Rebuttal).
[192] Ex. 305 at 3–4 (Peirce Surrebuttal).
[193] *Id.* at 3.

Settlement Agreement, the Department and DEA agreed that the following apportionment of revenue responsibility is reasonable:[194]

DEA/Department Proposed Revenue Apportionment

Customer Class	Current Revenue	DEA Proposed Revenue	DOC Proposed Revenue	Settlement Agreement Proposed Revenue	DOC % Chg.
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%

126. Because the OAG found that DEA's use of the minimum-size method biased the CCOSS against Residential and Farm class customers, the OAG asserted that it was not reasonable for DEA to weigh the CCOSS as heavily as it did for its rate design recommendations. Therefore, the OAG argued that DEA's revenue apportionment failed to appropriately balance rate design principles.[195]

127. The OAG offered an alternative revenue apportionment. The OAG's proposed revenue apportionment was based on a number of factors. These factors included the OAG's zero-intercept proxy-based CCOSS, as well as social welfare, consistency among classes, and concerns that rate increases be as smooth and predictable as possible. In addition, the OAG hoped to lessen the increase for the Small General Service class because DEA's original proposal increased that class significantly more than other classes.[196]

128. The OAG's proposed revenue apportionment compared to the final proposed revenue apportionment as reflected in the Settlement Agreement, is as follows:

[194] Ex. 128 at 13 (Settlement Agreement).
[195] Ex. 200 at 30 (Nelson Direct).
[196] *Id.* at 31.

OAG and Settlement Revenue Apportionment Comparison

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

129. The Administrative Law Judge finds that the OAG's proposed revenue apportionment is based in part on its CCOSS, which in turn utilized the zero-intercept proxy method. Because the record does not support the use or the results of the zero-intercept proxy method, the OAG's CCOSS, and its revenue apportionment which incorporated its CCOSS, are not reliable.

130. In addition, the Administrative Law Judge finds that by over-emphasizing the principle of balancing the revenue increases among classes, the OAG under-emphasized the importance of basing rate design on cost. For example, based on DEA's CCOSS, General Service class customers already pay more than 100 percent of their costs. The OAG's proposed revenue apportionment would place a significantly higher burden on General Service customers, significantly increasing inter-class subsidies.

131. The Administrative Law Judge finds that the revenue apportionment proposed in the Settlement Agreement imposes a more reasonable increase on General Service class customers in relation to their costs, while assigning a 2.79 percent increase to Residential and Farm class customers – a percentage that cannot reasonably be presumed to constitute rate shock, but will still bring this class closer to paying its costs.

132. The Administrative Law Judge finds that the revenue apportionment agreed to by DEA and the Department, as reflected in the Settlement Agreement, is just and reasonable and supported by the record. Therefore, the Administrative Law Judge respectfully recommends that the Commission adopt the revenue apportionment as set forth in the Settlement Agreement.

D. Rate Design – Customer Charges

1. Customer Charge Background

133. The fixed monthly customer charge is designed to cover the cost DEA incurs on a monthly basis, regardless of whether a customer uses any electricity.[197]

[197] Ex. 126 at 34 (Larson Rebuttal).

134. In this proceeding, DEA initially sought a $2.00 per month increase in Residential and Farm class fixed customer charges from $8.00 to $10.00.[198] DEA also proposed an increase of $4.00 per month, moving from $10.00 to $14.00, for Small General Service class customers.[199] The Department proposed increases of $1.00 per month for Residential and Farm class customers.[200]

135. The following table summarizes DEA's proposed increases to the fixed customer charges for the Residential, C&I Non-Demand, and C&I Demand customer classes, as well as the Department's proposed fixed customer charges:[201]

Summary of Fixed Customer Charges

<table>
<tr><th>Class</th><th>Customer Costs</th><th>Current Customer Charge</th><th>DEA Proposed Charge</th><th>DOC Proposed Charge</th></tr>
<tr><td>Residential & Farm</td><td rowspan="4">$23.39</td><td>$8.00</td><td>$10.00</td><td>$9.00</td></tr>
<tr><td>Residential & Farm Demand Control</td><td>$11.00</td><td>$13.00</td><td>$12.00</td></tr>
<tr><td>Residential & Farm Time of Day</td><td>$11.00</td><td>$13.00</td><td>$12.00</td></tr>
<tr><td>Residential TOD – New Schedule 55</td><td>-</td><td>$13.00</td><td>$12.00</td></tr>
<tr><td>Irrigation</td><td>$62.56</td><td>$24.00</td><td>$30.00</td><td>$30.00</td></tr>
<tr><td>Small Gen. Service</td><td>$33.28</td><td>$10.00</td><td>$14.00</td><td>$14.00</td></tr>
<tr><td>General Service</td><td rowspan="2">$69.45</td><td>$28.00</td><td>$34.00</td><td>$34.00</td></tr>
<tr><td>General Service – TOD</td><td>$30.00</td><td>$36.00</td><td>$36.00</td></tr>
<tr><td>C&I Interruptible</td><td>$188.92</td><td>$80.00</td><td>$110.00</td><td>$110.00</td></tr>
</table>

136. As part of the Settlement Agreement, DEA and the Department agreed on the Department's proposed Residential and Farm fixed customer charges.[202]

137. The Department explained that, to the extent that customer costs are not recovered through the fixed 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, the remaining customer costs are recovered through the usage charges paid by customers with higher levels of usage. If the fixed customer charge is less than fixed

[198] The proposed $8.00 to $10.00 increase would have applied to the basic Residential and Farm class customers. As illustrated in the Summary of Fixed Customer Changes at finding 135, other Residential and Farm Customer Classes (demand control, time of day) currently pay an $11.00 fixed customer charge. DEA's proposal would have increased each of these changes by $2.00 as well.

[199] Ex. 107, DEA-6 at 1 (Larson Direct Attachments).

[200] Ex. 304 at 10 (Pierce Direct).

[201] *Id.*

[202] Ex. 128 at 14 (Settlement Agreement).

customer costs, then customers who use more energy pay for costs that they do not impose on the system. These customers subsidize other customers within the same class who pay less than it costs to serve them. As a policy matter, the Department urged that such intra-class subsidies should be minimized.[203]

138. The OAG opposed any increases in the Residential and Farm class or the Small General Service class fixed customer charges.[204] In analyzing the proposed fixed customer charges, the OAG focused primarily on two policy goals: (1) maintaining a lower customer charge to benefit low-income customers; and (2) promoting conservation by increasing the volumetric charge.[205] In addition, the OAG criticized the Department's focus on intra-class subsidies.[206]

2. OAG Position Regarding Fixed Customer Charges

139. The OAG pointed out that a decrease in the fixed customer charge results in an increase in the volumetric charge. Therefore, maintaining a low customer charge benefits those customers with lower usage. Based on this reasoning, the OAG analyzed the impact that a lower customer charge would have on low-income customers.[207] The OAG maintained that its analysis demonstrated that low-use, low-income customers would be harmed by an increase in the fixed customer charge, while maintaining DEA's current customer charge would provide significant benefits to the company's low-income customers.[208]

140. The OAG also considered the impact of maintaining the $8.00 per month fixed customer charge versus implementing a $9.00 per month fixed customer charge on a high-use, low-income customer whose electricity use ranked in the 90th percentile for low-income customers.[209] Based on this analysis, the OAG determined that maintaining the $8.00 per month fixed customer charge would increase the overall monthly bill by only 60 cents more than increasing the fixed customer charge to $9.00 per month.[210]

141. With respect to its conservation concern, the OAG asserted that increasing the fixed customer charge tends to lessen increases in the volumetric charge

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203 Ex. 304 at 11 (Peirce Direct).

204 Ex. 200 at 42 (Nelson Direct). The OAG did not provide specific testimony regarding Residential & Farm Demand Control, Residential & Farm Time of Day, or Residential Time of Day – New Schedule 55. Without more, the Administrative Law Judge assumes the OAG wants the existing charges for those classes to stay the same, and the New Schedule 55 to match the $11.00 Residential & Farm Time of Day charge.

205 Ex. 200 at 42 (Nelson Direct).

206 Ex. 201 at 15 (Nelson Rebuttal).

207 *Id.* at 16-18.

208 Tr. at 80 (Nelson); Ex. 201 at 21 (Nelson Rebuttal).

209 Ex. 201 at 18 (Nelson Rebuttal).

210 *Id.*

while maintaining a lower fixed customer charge promotes conservation by increasing the volumetric charge.[211]

142. The OAG conducted an analysis to determine the conservation benefits of maintaining DEA's existing Residential and Farm class fixed customer charge.[212] The OAG claimed that its analysis demonstrates that maintaining the current customer charge would result in reduced energy consumption equivalent to eliminating 610 residential homes compared to the $10.00 per month fixed customer charge initially proposed by DEA.[213]

143. The OAG also objected to the proposed rate design as it applied to the Small General Service class. DEA proposed a 40 percent increase in the fixed customer charge, from $10.00 to $14.00 per month, and a 2 percent increase in the proposed volumetric rate. The OAG asserted that this rate design structure fails to encourage conservation.[214]

144. The OAG challenged the significance of the Department's testimony regarding intra-class subsidies on two bases. First, the OAG argued that there are intra-class subsidies, in addition to those caused by the fixed customer charge, which the Department did not take into account in its testimony. The OAG cited as examples "subsidies related to when residential customers use electricity, how much capacity is demanded from a residential customer, [and] where a customer is located within the utility's territory . . . ."[215]

145. In addition, the OAG maintained that the Department incorrectly and improperly used the CCOSS as a basis for the calculation of the fixed customer charge.[216] According to the CCOSS numbers calculated by DEA and agreed to by the Department, this amount is $23.39.[217]

146. Instead of determining the fixed customer charge based on DEA's CCOSS results, the OAG asserted that the charge should be based only on costs from DEA's distribution system. The OAG calculated that this amount is $11.41 for Residential and Farm class customers.[218]

147. Based on its calculation of an $11.41 fixed customer cost, the OAG reasoned that maintaining the $8.00 customer charge would result in an intra-class subsidy of only $3.41, rather than $15.39 as the Department claimed.[219] The OAG

[211] Ex. 200 at 36-37 (Nelson Direct).
[212] *Id.* at 39.
[213] Ex. 200, REN-11 (Nelson Direct).
[214] Ex. 200 at 38-39 (Nelson Direct).
[215] Ex. 201 at 15 (Nelson Rebuttal).
[216] *Id.* at 7. According to the CCOSS numbers calculated by DEA and agreed to by the Department, this amount is $23.39. *Id.*
[217] Ex. 108, DEA-7 at 1 (Larson Direct Attachments).
[218] Ex. 201 at 13 (Nelson Rebuttal).
[219] *Id.* at 14.

argued that these numbers demonstrate that the Department's analysis "overstates the intra-class subsidy by over four times."[220]

3. Department's Position Regarding Fixed Customer Charges

a. Low-income Customers

148. The Department recognized that the Commission has expressed concern in the past that high customer charges could be burdensome to low-income households. This assumes that the amount of energy used by low-income customers is below the breakeven point noted below.[221]

149. The Department emphasized the importance of insuring that the assumptions about energy use by low-income and other customers are correct, and verifying whether adoption of a rate design proposal benefits low-income customers.[222] The Department asserted that increasing the residential customer charge in a moderate manner helps to protect low-income customers who use higher-than-average levels of energy. These low-income customers are harmed by adoption of customer charges set below cost because they pay through their energy charge for customer costs imposed by low-use customers. The Department illustrated how this effect can be reduced by increasing the fixed customer charge, as shown below:[223]

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[220] *Id.*
[221] Ex. 304 at 14 (Peirce Direct).
[222] *Id.*
[223] *Id.*

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

		Current Customer Charge/Cost	Proposed Customer Charge/Cost
1	Residential customer cost[224]	$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[225]	95,586	95,586
7	Total annual customer costs recovered in energy charges	$17,652,822	$15,355,545
8	Divided by kWh sales[226]	879,773,544	879,773,544
9	Per-kWh recovery of customer costs in the energy charge	$0.02007	$0.01745
(3/9)	Breakeven usage amount (in kWh)	767	767

150. The Department explained that 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 the Department, based on 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 fixed-customer charge applied to those customer costs – in DEA's case $15.39 per customer per month – must be recovered through the energy charge.[227]

151. The Department calculated that, under current rates, an average DEA 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 each month. Based on the Department's numbers, at 500 kWh per

[224] Ex. 104 at 3 (Larson Direct Attachments).
[225] Ex. 102 at 13 (Larson Direct Attachments).
[226] *Id.*
[227] Ex. 304 at 15 (Peirce Direct).

month, a customer's payments would fall $3.36 short of the necessary $15.39 in customer costs needed to be recovered from the energy charge.[228]

152. The Department considered 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 is over 300 kWh more than the Department's breakeven 750 kWh in usage per month.[229] Based on the Department's calculations, if the fixed customer charge remains at $8.00, these LIHEAP customers would pay an additional $6.14 per month above their fixed customer costs, reflecting the recovery of customer costs for customers using less than approximately 750 kWh per month.[230]

153. The Department recommended a balance between increases in the usage charge and the fixed customer charge because the impact of increases in these two charges can affect different customers in different ways. Some low-income customers with low levels of monthly usage may be affected by a $1.00 per month increase in the monthly fixed customer charge. However, as noted in the example above, the Department was also concerned about DEA's LIHEAP recipients who have above-average usage and who subsidize low-use customers, on average, at a rate of $6.14 per month, and thus are harmed even more. Such customers would already be paying much higher electric bills than low-use customers. Consequently, the Department recommended balancing an increase to the fixed customer charge with the volumetric energy charge by increasing the fixed customer charge by $1.00 per month.[231]

b. Intra-class subsidies

154. The Department acknowledged that there are intra-class subsidies in addition to those created by the fixed customer charge. However, the Department did not consider them to be relevant to the customer-charge issue. Specifically, the Department noted that, traditionally, time-of-use rates have been considered too complex to administer to be required. In addition, the Department stated that service line extension charges serve as a way of limiting the subsidies related to a customer's location in the utility's service area.[232]

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[228] *Id.* at 16.

[229] 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, 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. 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 $8.00 per month rather than increased to $9.00 per month. Ex. 305 at 10 (Peirce Surrebuttal).

[230] Ex. 304, SLP-3 (Peirce Direct).

[231] Ex. 304 at 16–17 (Peirce Direct).

[232] Ex. 305 at 8-9 (Peirce Surrebuttal).

155. The Department disagreed with the OAG's approach to calculating the customer cost. Unlike the OAG, the Department included the cost of the primary line in the total customer cost when recommending a fixed customer charge. The Department stated it included the primary line because it remains a cost that is necessary for DEA to serve a customer. The Department asserted that electricity has to be delivered through the primary line to the customer's home, and the cost of the primary line continues, whether the customer uses any electricity in a given month or not.[233]

156. The Department also expressed concern that, as distributed generation (DG) facilities such as rooftop solar systems expand, utilities will increasingly need to insure that the fixed charges associated with serving their customers reflect their costs. The Department is aware that, as the number of DG facilities increases, utilities may lose energy sales but will still have to cover their fixed costs while minimizing the impact on customers who do not have DG facilities.[234] Therefore, the Department concluded, it is important to include the cost of the primary line in the fixed customer cost.[235]

157. The Department pointed out, however, that even excluding the cost of the primary line, the proposed monthly customer charge is below the cost of serving a customer, as shown below:[236]

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[233] *Id.* at 5-6.
[234] Tr. at 149-150 (Peirce).
[235] Ex. 305 at 5-6 (Peirce Surrebuttal); Tr. at 150 (Peirce).
[236] Ex. 201 at 7, 14 (Nelson Rebuttal); Ex. 305 at 5–6 (Peirce Surrebuttal).

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

		$8 Customer Charge (OAG)	$9 Customer Charge (Department)	$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[237]			
5	Annual customer costs recovered in energy charge, per customer	$43.80	$31.80	$19.80
6	* Avg. no. of customers[238]	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[239]	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

158. Based on the summary above, the Department maintained that, with an $8.00 fixed customer charge, an additional $0.00476 of customer costs would be recovered through the energy charge, whereas with a $9.00 fixed customer charge, an additional $0.00345 per kWh would be added to the energy charge. The difference in the energy charge is $.00131 ($0.00476 - $0.00345) or $0.13 for every 100 kWh of energy usage.[240]

159. The Department balanced the goal of moving monthly customer charges closer to cost with the goal of moderating changes in rate design, over time.[241] The Department pointed out that DEA has not requested a rate increase since 2009.[242] This focus on balancing competing goals and consequences of the fixed customer charge

[237] Line 4 appeared blank in original.
[238] Ex. 102 at 13 (Larson Direct Attachments).
[239] *Id.*
[240] Ex. 305 at 7 (Peirce Surrebuttal).
[241] *Id.* at 8.
[242] Ex. 304 at 11 (Peirce Direct).

led the Department to recommend a $1.00 increase in the residential customer charge to begin the process of moving those customers towards cost.[243]

4. DEA calculation of fixed customer costs

160. DEA based its fixed customer charge on the costs it incurs to "stand ready to provide electric service, excluding costs for the primary line."[244]

161. DEA's "identification of consumer costs and proposal for recovery in the monthly fixed charge reflects political, policy and rate design considerations."[245] DEA stated that, other considerations notwithstanding, the residential fixed customer charges "should be set at $23.39."[246] However, DEA noted both Commission and customer preference for lower monthly fixed charges. Therefore, it focused its recovery of fixed costs on a limited number of items, not including the primary line, although it continued to assert that the primary line is most appropriately part of the fixed monthly charge.[247]

162. Based on this reasoning, DEA calculated the customer costs amount for Residential and Farm class customers as $11.65. This amount includes the monthly costs of a transformer, meter and service, customer accounting, taxes and margin associated with plant costs.[248]

5. Conservation Considerations

163. The Department maintained that it is not reasonable to maintain the fixed customer charge if customer costs are not met, even in the name of conservation. The Department asserted that, 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, the Department concluded it would be an inappropriate price signal.[249]

164. Neither the Department nor DEA responded directly to the OAG's analysis regarding increased energy consumption as a result of a $10.00 per month fixed customer charge for Residential and Farm class customers, which was DEA's original recommended fixed customer charge.[250] However, the Department maintained that customers will continue to have an incentive to conserve energy, even if the fixed customer charge is increased to $9.00 per month, because increased energy use will result in higher bills due to the volumetric charge. In addition, DEA offers numerous energy conservation programs in conjunction with its wholesale provider GRE, including rebates, that encourage its customer-members to use less energy. DEA's energy

[243] Ex. 305 at 10-11 (Peirce Surrebuttal).
[244] Ex. 101 at 33 (Larson Direct).
[245] Ex. 127 at 15 (Larson Surrebuttal).
[246] *Id.*
[247] *Id.* at 16.
[248] Ex. 101 at 33 (Larson Direct).
[249] Ex. 304 at 13 (Peirce Direct).
[250] Tr. at 103-104 (Nelson).

savings and Conservation Improvement Program ("CIP") spending are reported as part of GRE's CIP program results.[251] The Department noted that 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.[252]

6. Customer Charge Recommendations

165. The Administrative Law Judge finds that the level of fixed customer charge affects the extent to which volumetric charge subsidizes the actual fixed costs of providing service. The closer a fixed customer charge is to the actual cost of providing service, the less of the volumetric charge will be used to subsidize fixed costs. Therefore, artificially low fixed customer charges tend to result in higher-use customers subsidizing the fixed costs of lower-use customers. Conversely, higher fixed customer charges, if they are close to the fixed cost of providing service, provide a more accurate account to customers of the actual fixed cost of utility service and are more fair, financially, to higher-use customers.

166. In addition, the Administrative Law Judge finds that the record in this matter demonstrates that at the current $8.00 fixed customer charge, some low-income, higher-use customers subsidize low-use customers, on average, at a rate of $6.14 per month. These low-income, high-use customers are harmed even more than the low-income, low-use customers would be by a $1.00 per month increase in the customer charge, which would lower the intra-class subsidy. This concern about the intra-class subsidy, including its effect on low-income customers, drove the Department's proposal to increase the fixed customer charge to $9.00 per month.

167. The Administrative Law Judge finds that there is adequate support in the record to conclude that DEA's proposed Residential and Farm class fixed customer charge rate design includes sufficient conservation incentives, even with a $9.00 fixed customer charge. In the view of the Administrative Law Judge, the OAG's analysis of energy savings to be achieved by maintaining a lower fixed-customer charge fails to account for the common-sense argument that DEA's conservation incentives will continue to promote conservation. These incentives include the customer's incentive to lower monthly bills by lowering volumetric use and thus the volumetric portion of the bill, as well as the conservation improvement programs in which DEA and its energy partner, GRE, will continue to participate.

168. The OAG raises a noteworthy argument that the customer charge should be based solely on the secondary, fixed costs of the customer rather than the primary line. The OAG's concerns in this regard are especially salient in view of the concerns raised about the minimum-size method and the extent to which some distribution costs remain in the customer costs. However, the OAG did not provide precedent for approaching the fixed-customer charge calculation in this manner. In addition, the

[251] Ex. 304 at 13-14 (Peirce Direct).
[252] *Id.* at 13–14; Tr. at 155-157 (Peirce).

Department raised important questions that were not addressed by the OAG regarding how DG facilities should be factored into this calculation. Furthermore, regardless of which party's calculation of fixed customer costs is used, it is undisputed that a $1.00 increase in the fixed customer charge will still leave a portion of the Residential and Farm Service class costs unpaid.[253]

169. Because a $1.00 increase in the fixed customer charge supports the principles of gradually bringing the fixed customer charge to the class's fixed cost of service in a manner that does not promote intra-class subsidies or discourage conservation, the Administrative Law Judge respectfully recommends that the Commission approve the proposed $1.00 increase in the Residential and Farm class service fixed customer charges.

170. With regard to DEA's proposal to increase the fixed customer charge for the Small General Service class by 40 percent (or $4.00), the Administrative Law Judge finds this proposal fails to adequately consider the principles favoring gradual increases in fixed customer charges, avoiding rate shock and encouraging reasonable efforts toward conservation. While the parties provided little testimony specific to this customer class, the Administrative Law Judge notes that a 40 percent increase in the fixed customer charge is not gradual and could constitute rate shock.[254] The increase is especially troubling given that the proposed increase in this class's volumetric charge is only 2 percent, an amount that, if increased, could support conservation goals more strongly. While the Administrative Law Judge recognizes the importance of bringing fixed customer charges closer to each class's fixed cost of service, this proposal increases the Small General Service class too abruptly. The Administrative Law Judge respectfully recommends that the Commission approve a fixed customer charge of $12.00, which would be a 20 percent increase for the Small General Service class, and adjust the volumetric charge accordingly.

171. The Administrative Law Judge respectfully recommends that the Commission approve all of the remaining proposed fixed customer charges in accordance with the Settlement Agreement.

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

CONCLUSIONS OF LAW

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50 and 216B.01-.82 (2014).

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[253] The Department's calculation is $23.39, DEA's is $11.65 and the OAG's is $11.41. *See* Findings 150, 162, and 146.
[254] *See* Ex. 128 at 14 (Settlement Agreement).

2. The public and the parties received proper and timely notice of the hearing and DEA complied with all procedural requirements of statute and rule.

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of Minn. Stat. §§ 216B.164, .241, 216C.05 (2014).

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.

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

6. The record supports the resolution of the settled, resolved, and uncontested matters set forth in Section IV of this Report. These matters have been resolved in the public interest and are supported by substantial evidence.

7. Modifying DEA's rates in accordance with this Report results in just and reasonable rates that are in the public interest within the meaning of Minn. Stat. § 216B.11.

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

9. The final rates ordered by the Commission should be compared to the interim rates set in the Commission's Order Setting Interim Rates, issued September 23, 2013, and a refund ordered to the extent that the interim rate exceeds the final rate, subject to any true-up that is ordered.

10. Any Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such.

Based upon these Conclusions of Law, the Administrative Law Judge makes the following:

RECOMMENDATION

The Administrative Law Judge recommends that:

1. DEA be authorized to increase gross annual revenues in accordance with the terms of this Report.

2. Consistent with the time period specified in a Notice to be issued by the Commission, DEA shall file with the Commission for its review and approval, and serve

on all parties in this proceeding, a revised rate base, income statement, and revenue requirement summary, a schedule of the class revenue allocations and all billing determinants, that reflect the test year revenue requirement and rate design recommended by the Administrative Law Judge.

3. The Commission incorporate the resolutions reached by the parties in the course of this proceeding into its Order.

4. The Commission adopt the recommendations set forth in the Findings above.

5. DEA make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: March 2, 2015

LAURASUE SCHLATTER
Administrative Law Judge

Reported: Transcript Prepared
Shaddix & Associates

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the timeframe established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2013), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Rule 7829.2700, subpart 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS

600 North Robert Street
Saint Paul, Minnesota 55101

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March 2, 2015

See Attached Service List

Re: In the Matter of the Application by Dakota Electric Association for Authority to Increase Rates for Electric Service In MN

OAH 80-2500-31796
MPUC E-111/GR-14-482

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS** in the above-entitled matter.

If you have any questions, please contact my legal assistant Rachel Youness at (651) 361-7881 or rachel.youness@state.mn.us.

Sincerely,

s/LauraSue Schlatter

LAURASUE SCHLATTER
Administrative Law Judge

LS:ry
Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

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

Rachel Youness, certifies that on March 2, 2015 she served the true and correct **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

Anderson	Julia	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	Electronic Service	Yes
Bahn	Andrew	Andrew.Bahn@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Barlow	Ryan	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	Electronic Service	Yes
Dobson	Ian	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Electronic Service	Yes
Harding	Robert	robert.harding@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Hintz	Corey	chintz@dakotaelectric.com	Dakota Electric Association	Electronic Service	No
Jensen	Linda	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	Electronic Service	Yes
Krishnan	Ganesh	ganesh.krishnan@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Larson	Douglas	dlarson@dakotaelectric.com	Dakota Electric Association	Electronic Service	Yes
LeVander, Jr.	Harold	hlevander@felhaber.com	Felhaber, Larson, Fenton & Vogt, P.A.	Electronic Service	Yes
Lindell	John	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	Electronic Service	Yes
Madsen	Peter	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Electronic Service	Yes
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Morrissey	Dorothy	dorothy.morrissey@state.mn.us	Public Utilities Commission	Electronic Service	Yes
Schlatter	LauraSue	LauraSue.Schlatter@state.mn.us	Office of Administrative Hearings	Electronic Service	Yes
Shaddix Elling	Janet	jshaddix@janetshaddix.com	Shaddix And Associates	Electronic Service	Yes
Weflen	Lou Ann	lweflen@dakotaelectric.com	Dakota Electric Association	Electronic Service	Yes
Wolf	Daniel P	dan.wolf@state.mn.us	Public Utilities Commission	Electronic Service	Yes