STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION
for Authority to Increase Rates for
Electric Service in Minnesota

Docket No. E-111/GR-14-482

PREFILED DIRECT TESTIMONY OF
DOUGLAS R. LARSON
VP OF REGULATORY SERVICES
DAKOTA ELECTRIC ASSOCIATION

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DOUGLAS R. LARSON
VICE PRESIDENT OF REGULATORY SERVICES
DAKOTA ELECTRIC ASSOCIATION

I. QUALIFICATIONS

Q. Please state your name.

A. My name is Douglas R. Larson.

Q. Where are you employed?

A. I am employed by Dakota Electric Association (DEA, Dakota Electric, or Cooperative). Dakota Electric's headquarters are located at 4300 220th Street West, Farmington, Minnesota 55024.

Q. Please describe the business activities of Dakota Electric.

A. Dakota Electric Association was founded in 1937 as a non-profit, member-owned distribution electric utility. It serves more than 103,000 members in an area covering much of Dakota County, just south of Minneapolis and St. Paul. Dakota Electric also provides electric service in portions of Scott, Rice and Goodhue counties.

Dakota Electric purchases wholesale electricity from Great River Energy (GRE), located in Maple Grove, Minnesota.

A twelve-person elected board of directors made up of members governs the Cooperative. Dakota Electric is also regulated by the Minnesota Public Utilities Commission and is the only rate-regulated electric cooperative in Minnesota.

Q. Please describe your responsibilities with Dakota Electric Association.

A. I am Vice President of Regulatory Services. In this position, I am responsible for 1) developing new rates, monitoring existing rates, submitting miscellaneous tariff filings, and coordinating and/or preparing all necessary information pertaining to rate increase filings; 2) evaluating power supply issues through participation in meetings at Great River Energy; and 3) monitoring state and federal electric utility and environmental legislation and determining the potential affect on DEA's operation as a distribution cooperative.

Q. What is your educational and professional background?

A. My educational and professional background is summarized in Schedule 1 attached to this direct testimony.

Q. Have you previously presented testimony before the MPUC?

A. Yes. Schedule 2 attached to this direct testimony identifies the electric and natural gas utility general rate case proceedings, electric service territory compensation hearings, the contested rulemaking and the certificate of need proceeding in which I have presented testimony before the MPUC.

Q. Have you submitted testimony to other state regulatory commissions?

A. Yes. Schedule 2 attached to this direct testimony also identifies the electric utility general rate case proceedings in which I have presented testimony before other state regulatory commissions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the analysis of Dakota Electric's revenue requirements, class cost of service study and proposed rates within the context of the 2013 Historical Test Year, adjusted for known and measurable changes.

Q. Please identify the exhibits included with your testimony.

A. The following exhibits are included as part of my testimony:

Exhibit__(DEA-1)	Statement of Operations - Present Rates
Exhibit__(DEA-2)	Determination of Revenue Requirements
Exhibit__(DEA-3)	Cost of Service Analysis
Exhibit__(DEA-4)	Load Management Cost Analysis
Exhibit__(DEA-5)	Statement of Operations - Proposed Rates
Exhibit__(DEA-6)	Comparison of Present and Proposed Rates
Exhibit__(DEA-7)	Monthly Fixed Charge Analysis
Exhibit__(DEA-8)	Coincidental Demand Charges
Exhibit__(DEA-9)	Summary of Lead-Lag Study
Exhibit__(DEA-10)	Special Fees and Charges
Exhibit__(DEA-11)	Line Extension Analysis
Exhibit__(DEA-12)	Base Calculations for Resource and Tax Adjustment
Exhibit__(DEA-13)	Air Conditioning Analysis
Exhibit__(DEA-14)	Standby Rate Analysis
Exhibit__(DEA-15)	Electric Vehicle Rate Analysis
Exhibit__(DEA-16)	Residential TOU – New Proposed Schedule 55
Exhibit__(DEA-17)	Present Rate Schedules
Exhibit__(DEA-18)	Blackline Mark-up of Present Rate Schedules
Exhibit__(DEA-19)	Proposed Rate Schedules

Q. Please identify the documents included in the workpapers you have submitted:

A. The workpapers include the following documents:

1) Form 7s 2009-2013
2) Audited 2013 Financials and 2013 Annual Report
3) Accounting System Description and Cross-Reference Projects to Form 7
4) 2014 Budget (2012 & 2013 Actual)
5) Long Range Forecast
6) Lead-Lag Study Detail
7) Cost Allocation Policy
8) Depreciation Summary
9) Conservation Improvement Program
10) Estimate of System Losses and System Own Use
11) Individual Customer Actual 2013 Usage and Demand by Rate Class
12) Monthly Billed Sales 2008-2013
13) Sales History and Forecasted Test Year Normalization
14) Property Tax Detail
15) Travel, Entertainment and Related Employee Expenses
16) Test Year Adjustments Bridge Schedule
17) Long Term Interest Expense / Prudently Incurred
18) Advertising
19) Donations / Charitable Contributions
20) Organizational Dues
21) Minimum Size Method
22) ALJ Report from 2009 General Rate Case
23) PUC Final Order from 2009 General Rate Case

Q. Has the material included in your exhibits and workpapers been prepared by you or by others under your direction?

A. The exhibits and workpapers I am sponsoring have been prepared by myself and others at Dakota Electric. In addition, the cost of service study model was completed by Richard J. Macke at Power System Engineering, Inc.

III. SUMMARY OF FILING

Q. What are Dakota Electric's objectives in filing this general rate case?

A. As Mr. Miller (Dakota Electric's President and CEO) indicates in his direct testimony, Dakota Electric has two objectives in filing this general rate case. The first objective is financial. As Mr. Miller indicates, Dakota Electric projects minimal operating margins of about $664,000 in the 2014 budget, making an increase in rates necessary and unavoidable. This general rate filing will allow the Cooperative to increase distribution operating revenues and achieve acceptable financial operating results. The second objective of this general rate filing is to make continuing progress in aligning class rates and revenue with the cost of providing service.

Q. Would you please summarize the revenue requirement, COS study results and proposed rate design results contained in your testimony?

A. <u>Revenue Requirements -- Summary</u>

The revenue requirements of the Cooperative simply refer to the total cost of doing business and are comprised of operating expenses plus margin requirements. By comparing the revenue requirements against present revenue, the adequacy of the present rates can be assessed; and a general change in rates can be discussed.

Operating expenses for the Cooperative (excluding interest) total $192,961,304. We have calculated a proposed Rate of Return (ROR) on rate base of 6.52 percent, resulting in a required revenue increase of $4,189,232 or 2.11 percent. The following table presents a summary of the revenue requirements analysis for the 2013 Test Year:

Table 1
Revenue Requirements Summary

			($)
1.	Operating Expenses (Excluding Interest)		192,961,000
2.	Margin Requirements		
	a.	Rate Base	171,614,000
	b.	Rate of Return	6.52%
	c.	Return Required	11,191,000
	d.	Less: Non-Operating Income [1]	399,000
	e.	Net Operating Income Required	10,792,000
3.	Total Revenue Requirements		203,753,000
4.	Revenue From Present Rates		
	a.	Tariff Revenue (net of RTA)	198,872,000
	b.	Other Operating Revenue	692,000
	c.	Total Revenue	199,564,000
5.	Potential Increase (Decrease)		4,189,000
		or	2.11%

Class Cost of Service -- Summary

Once the overall revenue requirements analysis was complete, the class Cost of Service (COS) analysis was prepared by Power System Engineering, Inc. This analysis is aimed at identifying the cost responsibility of each rate class and uses the same model approved by the MPUC in our 2003 and 2009 general rate cases with two refinements described later in my testimony. The COS is also useful in determining the cost components of each rate class (i.e. member, energy and demand costs). The results of the class COS analysis are summarized on the following table:

Table 2
Cost of Service Summary

Rate Class	Revenue Present Rates[1]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[2]
	($)	($)	($)	(%)
Residential & Farm (31,32,53)	112,384,414	115,576,812	3,192,398	2.85
Small General Service (41)	6,674,522	7,171,338	496,817	7.47
Irrigation (36)	977,226	997,009	19,783	2.03
General Service (46,54)	47,909,060	47,749,413	(159,647)	-0.33
C&I Interruptible (70,71)	26,594,877	27,212,425	617,548	2.33
Lighting	1,999,160	2,021,495	22,335	1.12
			Total System	2.11

As the above table illustrates, required revenue changes are very similar for most classes, except Small General Service Schedule 41. It is important, at this point, to distinguish between the COS and actual rate design. Due to the limitations inherent to a COS analysis, these results should be viewed as providing a general range of where rates should be. It is, in fact, uncommon for rates to be designed exactly in line with COS results.

1 Includes an allocated share of Other Operating Revenue.
2 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

Proposed Rates – Summary

Using the completed COS analysis, and in conjunction with Dakota Electric management and board of directors, we developed proposed rates. These rates are designed to meet various objectives of Dakota Electric and are discussed later in my testimony. The following table summarizes the impact of the proposed rates on Dakota Electric's rate revenue by service schedule:

Table 3
Comparison of Revenue
Present and Proposed Rates

(a) Line No.	(b) Rate Class	(c) Revenue Present Rates ($)	(d) Revenue Proposed Rates ($)	(e) Increase (Decrease) Amount ($)	(f) Increase (Decrease) Percent (%)
1	Residential & Farm Service (31)	113,330,908	116,469,554	3,138,646	2.77
2	Residential & Farm Demand Control (32)	48,617	50,073	1,456	2.99
3	Electric Vehicle (33)	1,037	989	(48)	(4.63)
4	Irrigation Service (36) Firm	69,220	72,307	3,087	4.46
5	Irrigation Service (36) Interruptible	904,565	920,980	16,415	1.81
6	Small General Service (41)	6,767,752	7,111,447	343,695	5.08
7	Security Lighting Service (44)	158,673	160,230	1,557	0.98
8	Street Lighting Service (44-2)	494,127	499,146	5,019	1.02
9	Street Lighting System (44-1)	66,583	67,243	660	0.99
10	Custom Residential Street Lighting (44-3)	1,272,737	1,285,813	13,076	1.03
11	Low Wattage Unmetered Service (45)	5,184	6,480	1,296	25.00
12	General Service (46)	47,284,619	47,313,119	28,500	0.06
13	Municipal Civil Defense Sirens (47)	3,900	3,900	-	-
14	Geothermal Heat Pump (49)	32,921	36,406	3,485	10.59
15	Controlled Energy Storage (51)	404,057	419,307	15,250	3.77
16	Controlled Interruptible Service (52)	2,481,912	2,575,568	93,656	3.77
17	Residential & Farm Time of Day (53)	31,553	32,474	921	2.92
18	General Service Time of Day (54)	455,726	446,035	(9,691)	(2.13)
19	Standby Service (60)	56,550	60,990	4,440	7.85
20	Full Interruptible Service (70)	24,579,461	25,096,828	517,367	2.10
21	Partial Interruptible Service (71)	1,921,760	2,003,538	81,778	4.26
22	Cycled Air Conditioning Service (80)	(1,539,168)	(1,664,599)	(125,431)	8.15

IV. REVENUE REQUIREMENTS

Q. Please summarize the concept of revenue requirements.

A. In order to ensure financial viability, the Cooperative's retail rates must generate sufficient revenue to meet operating expenses and margin requirements. The margin requirement must in turn be adequate to cover interest expense, meet our lenders financial covenants and accomplish other capital management objectives such as rotating patronage capital and maintaining (or achieving) the desired equity position. In this testimony I will refer to the total operating expense and margin requirement as the "revenue requirements" of the Cooperative. This is expressed by the following equation:

REVENUE REQUIREMENTS = OPERATING EXPENSE + MARGIN REQUIREMENT

To evaluate a cooperative's revenue requirement and the adequacy of its present rate structure to meet the requirement, it is common practice to analyze revenue and costs for a 12-month period of time called the Test Year.

Q. What Test Year was used to determine revenue requirements?

A. The Test Year revenue requirements for the study were based on Dakota Electric's actual historical operations for calendar year 2013, with adjustments for known and measurable changes.

Q. Have you prepared a Statement of Operations for the Test Year based on the revenue generated by DEA's present rates?

A. Yes. Exhibit__(DEA-1) provides a Statement of Operations for the Test Year based on the revenue generated by DEA's present rates.

Page 1 of Exhibit__(DEA-1) provides a summary of the Statement of Operations for the historical Test Year calendar 2013. The results shown in Column C reflect an unadjusted Test Year as actually recorded on DEA's books for the period January 1, 2013 through December 31, 2013 and correspond to the results shown in Exhibit__(DEA-2), page 1, Column C. Column D summarizes the various normalizing adjustments to the revenue and expense accounts proposed by the Cooperative with the resulting adjusted Pro Forma Test Year shown in Column E.

Page 2 of Exhibit__(DEA-1) provides a summary of each of the proposed adjustments. Pages 3 through 10 of Exhibit__(DEA-1) provide the detailed calculations for the following adjustments:

- Payroll;
- Payroll benefits;
- Depreciation;
- Other Adjustments;
- Property taxes;
- Reduction in CIP spending 2013 actual to 2014 budget;
- Regulatory filing fees;
- Rate Case filing fees recovery over 5 years; and
- Net deduction for disallowed expenses.

Page 11 of Exhibit__(DEA-1) presents the average number of consumers, energy sales, billing demand and revenue for Dakota Electric's rate classes as recorded for calendar year 2013.

Pages 12 through 19 of Exhibit__(DEA-1) present the calculation of revenue under present rates for the Pro Forma Test Year. That is, these pages multiply Pro Forma Test Year number of consumers, energy sales and billing demand times appropriate service schedule rates to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on Dakota Electric's present tariffed fixed, energy and demand rates for various rate schedules, including the Resource and Tax Adjustment (RTA) charges and/or credits that became effective on January 1, 2014. The calculation of forecasted Test Year billing units is shown in Workpaper 13. The forecasted billing units rely on regression analysis for the residential rate class which is most sensitive to fluctuating consumption based on changing weather. For those classes that do not experience such consumption fluctuations due to weather, the Test Year billing units reflect average energy and demand for each class multiplied times budget average number of members for the respective classes.

Finally, page 20 of Exhibit__(DEA-1) presents an overview of wholesale power costs.

Q. What are Dakota Electric's Test Year revenue requirements?

A. Exhibit__(DEA-2) summarizes the operating results for DEA on both an unadjusted and an adjusted basis for the Test Year ended December 31, 2013. A summary of the Operating Statement is provided as follows:

Table 4
Statement of Operations - Present Rates

Description	**2013 Actual**	**Pro Forma Test Year**
	($)	($)
Operating Revenue	193,896,154	199,564,247
Operating Expenses[3]	186,252,480	192,961,304
Net Operating Income	7,643,674	6,602,943
Non-Operating Income		
Capital Credits	8,694,772	8,694,772
Other	399,147	399,147
Subtotal	9,093,919	9,093,919
Total Margins	16,737,593	15,696,862

It should be emphasized that the Net Operating Income stated is before interest expense on long term debt is deducted.

Furthermore, it is important to distinguish between operating income or margins and total income. Use of the term "operating" is intended to designate revenue and expenses associated with the basic utility function (i.e., supplying electric distribution service to members). It is to be distinguished from Non-Operating Income, such as interest earnings from short-term investments and patronage capital credit assignments from associated organizations. Because Non-Operating Income is outside the operations and direct control of the distribution cooperative, it is not generally considered in establishing the revenue requirement for retail ratemaking purposes. Retail rates are generally designed to be sufficient, but only sufficient, to cover the operating revenue requirement, with credit sometimes given to interest earnings.

[3] Before interest expense is deducted.

Page 1, Column D of Exhibit__(DEA-2) shows that, in order to achieve the required ROR of 6.52 percent, present rates would need to be increased by $4,189,232 or about 2.11 percent.

Q. How was Dakota Electric's margin requirement calculated?

A. To complete the Test Year Revenue Requirement, an appropriate level of margin must be added to the previously determined operating expenses. In establishing the level of margin required to achieve the Cooperative's financial objectives, we have determined an appropriate return on rate base using a calculation methodology recommended by the Department of Commerce and approved by the Commission in our last general rate case.

Q. Please explain your determination of Rate of Return.

A. The Rate of Return method for establishing the Cooperative's margin requirement has been used by the Commission in Dakota Electric's general rate cases since we have been rate-regulated in the early 1980's. The ROR method is intended to ensure that earnings are sufficient to cover the cost of debt (interest) and generate a fair return on the investment (equity) for the owners. When applied to cooperatives, the concept is intended to permit the development of sufficient margins to cover the cost of debt and equity capital. However, in the case of cooperatives, the term "return on equity" involves a totally different concept than it does for investor-owned utilities. Return on (or of) equity for cooperatives is related to the retirement, or rotation, of patronage capital. Thus, the ROR required by a specific cooperative must result in sufficient margins to:

1. Pay interest expense on long-term debt;
2. Rotate patronage capital as stated in the policy of the cooperative;
3. Maintain or achieve the desired equity position; while

4. Meeting the financial covenants of our lenders.

Q. Has the rate-based ROR approach as applied to cooperatives been endorsed by the MPUC?

A. Yes. The method was originally endorsed by the MPUC in 1976 in a case involving Anoka Electric Cooperative (Docket No. U-75-103). Since that time, it has been used in all other cases involving cooperatives, including DEA's last rate filing (Docket No. E-111/GR-09-175).

Q. Please provide an overview of Dakota Electric's Rate of Return calculation.

A. The calculations necessary to determine the Cooperative's overall Rate of Return (ROR) are shown on pages 2 through 8 of Exhibit__(DEA-2). Page 2 of Exhibit__(DEA-2) shows the calculation of the Cooperative's Rate Base, with page 3 providing the supporting detail for Materials & Supplies used in the determination of Rate Base. Page 4 summarizes Dakota Electric's loans with the National Rural Utilities Cooperative Finance Corporation (CFC), Farmer Mac, and CoBank. This page includes new and refinanced debt (at more favorable rates) that occurred at the very beginning of calendar-year 2014. The impact of this debt in the rate case is to lower the weighted cost of debt by 0.32 percentage points. The Cooperative's overall weighted cost of debt used in the Test Year is 5.31 percent. Page 5 of Exhibit__(DEA-2) reviews Dakota Electric's historic total capitalization (debt and equity) for the years 1998 through 2013. We note that the mean growth rate in historic total capitalization for 2008 through 2013 is estimated to be 2.52 percent. Page 6 of Exhibit__(DEA-2) shows the calculation of the natural logarithm asset growth rate. Dakota Electric applied the 5 year exponential growth rate in the rate of return calculation as was used in the last general rate case. The five year period encompasses near-term years with more certainty in the growth forecast and aligns with our general expectation of filing rate cases at approximately five year intervals. Page 7 of Exhibit__(DEA-2) presents various ratio calculations. Finally, page 8 of Exhibit__(DEA-2) shows the calculation of DEA's 6.52 percent proposed ROR on rate base. (It is worth noting that this return is only about 1.2 percentage points more than the Cooperative's overall weighted cost of debt.)

Q. Please identify the input assumptions used to calculate the overall ROR on rate base.

A. The input assumptions used to calculate the overall ROR on rate base are as follows:

Asset Growth Rate	2.45%
Equity Ratio	53.285%
Debt Ratio	46.715%
Test Year Total Capital	$ 229,589,977
Test Year Total Equity	$ 136,837,360
Test Year Total Debt	$ 92,752,617
Annual Capital Credits	$ 2,500,000
Rate Base	$ 171,613,635
Cost of Long-Term Debt	5.31%

Q. Please identify the calculation for determining return on equity.

A. The calculation for determining the 4.49 percent return on equity is as follows:

$$\boxed{K = g + (CC/(ER \times TC))}$$

where: K = Rate of Return on Equity
g = Growth
CC = Capital Credits
ER = Equity Ratio
TC = Total Capital

Q. Please identify the calculation for determining overall cost of capital.

A. The calculation for determining the 4.87 percent overall cost of capital is as follows:

$\boxed{OCC = (ER \times K) + ((1 - ER) \times i)}$

where: OCC = Overall Cost of Capital
ER = Equity Ratio
K = Rate of Return on Equity
i = Cost of Long-Term Debt

Q. Please identify the calculation for determining overall rate of return on rate base.

A. The calculation for determining the 6.52 percent overall rate of return on rate base is as follows:

$\boxed{ROR = OCC \times (TC/RB)}$

where: ROR = Return on Rate Base
OCC = Overall Cost of Capital
TC = Total Capital
RB = Rate Base

Q. How does Rate of Return on Rate Base relate to the financial performance requirements of the Cooperative's lenders?

A. Rate of return on rate base is <u>not</u> a financial performance metric used by Dakota Electric's lenders.

Q. Please explain.

A. The financial performance metric used by our lenders is Modified Debt Service Coverage (MDSC). MDSC measures the number of times operating cash flow covers debt service on long-term debt. MDSC is calculated as follows:

MDSC = (Operating Margins + Non-Operating Margins-Interest + Interest Expense + Depreciation and Amortization Expense for year + Cash received in respect of Generation and Transmission and other Capital Credits)/(All payments of principal and interest during calendar year)

For the National Rural Utilities Cooperative Finance Corporation (CFC), Dakota Electric must maintain at least a 1.35 modified debt service coverage ratio calculated as an average of the two highest, out of the most recent three years. The 1.35 MDSC is a default threshold.

For CoBank, Dakota Electric must maintain at least a 1.25 modified debt service coverage ratio each year. The 1.25 MDSC is an annual default threshold.

Q. How do the proposed Test Year results translate to MDSC for the Cooperative?

A. The filed pro forma revenue requirement using the 6.52 percent calculated rate of return results in a Test Year calculated MDSC of about 1.8.

Q. How do these results compare to the MDSC financial performance of other cooperatives?

A. Benchmark information from CFC for 1) all cooperatives in the country, 2) Minnesota cooperatives, and 3) cooperatives of similar size to Dakota Electric is as follows:

"US Total" MDSC:
- Annual 5 yr. avg. = 1.85
- 2 of 3 yr. high avg. = 1.98

Minnesota MDSC:
- Annual 5 yr. avg. = 1.67
- 2 of 3 yr. high avg. = 1.80

Similar Size Cooperative MDSC:
- Annual 5 yr. avg. = 1.92
- 2 of 3 yr. high avg. = 2.01

Dakota Electric's calculated Test Year MDSC of about 1.8 is near the low end of these benchmark ranges.

Q. Why is this a concern for Dakota Electric?

A. Dakota Electric's Test Year is based on historic 2013 operating results with adjustments for known and measurable changes. Recent experience has shown that the time for us to prepare a general rate case filing and then proceed through the regulatory process can take at least one and a half years before final rates are implemented. The actual MDSC we achieve can be materially below the calculated Test Year amount. This means that Dakota Electric would be operating well below the industry ranges identified above. Adding to our concern is the more recent history of flat sales and the potential negative impact that weather can have on remaining above our financial performance default thresholds.

Q. How does Dakota Electric propose this matter be addressed?

A. Dakota Electric is <u>not</u> proposing any adjustment in this proceeding to increase revenue to achieve a higher Test Year MDSC. However, we request a Commission finding that MDSC levels may be used to modify the proposed and approved rate of return for Dakota Electric in future general rate cases. Of course, we expect that any such modification would require justification. Guidance in this regard would be very helpful.

Q. Please summarize Dakota Electric's revenue requirements in this proceeding.

A. A summary of the revenue requirements is presented in Table 5. The details of these calculations are provided in Exhibit__(DEA-2).

Table 5
Revenue Requirements Summary

			($)
1.	Operating Expenses (Excluding Interest)		192,961,000
2.	Margin Requirements		
	a. Rate Base		171,614,000
	b. Rate of Return		6.52%
	c. Return Required		11,191,000
	d. Less: Non-Operating Income[4]		399,000
	e. Net Operating Income Required		10,792,000
3.	Total Revenue Requirements		203,753,000
4.	Revenue From Present Rates		
	a. Tariff Revenue (net of RTA)		198,872,000
	b. Other Operating Revenue		692,000
	c. Total Revenue		199,564,000
5.	Required Increase (Decrease)		4,189,000
		or	2.11%

Q. What level of net operating income is DEA proposing?

A. DEA has established a proposed level of net operating income (before interest expense) of about $10,792,000. The calculation of this net operating income is shown above in Table 5 and in Exhibit__(DEA-2).

Q. What overall revenue increase is DEA requesting?

A. A summary of the proposed increase is shown in the above Table 5 with detailed calculations shown in Exhibit__(DEA-2). To eliminate the present revenue deficiency, annual revenue must be increased by $4,189,232 or approximately 2.11 percent.

4 Exclude capital credits assigned to the Cooperative.

V. COST OF SERVICE ANALYSIS

Q. Have you prepared a Cost of Service study for Dakota Electric?

A. Yes. A class COS analysis has been prepared to provide information to be used in designing rates. The basic objective of this analysis is to identify the cost of providing service to each rate class as a function of load and service characteristics. The methodology employed is often referred to as the "fully allocated average embedded" COS approach meaning that 1) costs are allocated on an average system-wide basis, and 2) embedded or accounting costs as recorded on the Cooperative's books are used in the analysis. We believe that this is generally the most appropriate technique to use in allocating cost responsibility to the various classes and developing rate design data and this has been confirmed by the Commission's approval of our cost of service study and methods in past rate cases.

Q. Has Dakota Electric used the same cost of service study model approved by the Commission in your last general rate case?

A. Yes, the cost of service study model is the same model approved by the Commission in our last rate case, with two modifications.

Q. Please explain the first modification.

A. In the Commission's final Order in Dakota Electric's 2009 general rate case in Docket No. E-111/GR-09-175, Ordering Paragraph #6 required that:

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

In compliance with this Order, we have used the minimum size method to classify specified distribution accounts. Workpaper 21 describes the calculation of minimum size classification factors for the respective distribution accounts and compares the overall results to the overall classification using the zero-intercept method from the 2009 case.

Q. Please explain the second modification.

A. Since our last rate case, our wholesale power supplier has implemented a new ancillary service energy charge. The new cost of service study distributes these ancillary service energy costs into each energy cost component based upon the kWh purchases and the ancillary services rate.

Q. Please describe Exhibit__(DEA-3).

A. Exhibit__(DEA-3) includes the COS analysis for Dakota Electric. The detailed calculations and assumptions that go into the analysis are as follows:

Page	Description
1-3	Cost of Service Summary
4-5	Classification of Plant in Service
6-7	Adjusted Statement of Operations
8-13	Classification of Revenue Requirements
14-17	Summary of Classification Factors
18	Summary of Allocation of Revenue Requirements to Rate Classes
19	Allocation of Plant in Service to Rate Classes
20-22	Allocation of Revenue Requirements to Rate Classes
23	Rate Class Weighting Factors
24	Analysis of Class Load Characteristics
25-40	Analysis of Class Demand Characteristics
41-42	Development of Allocation Factors

Q. How should the results of a COS be used?

A. It is vital at the outset to recognize some of the inherent limitations of such a study. First, it must be emphasized that a COS analysis, while basically an engineering evaluation, is an art; not an exact science. There are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can affect the results of the analysis, the results should be treated as providing an indication of the general range of class cost responsibility; and not as precise values.

Second, a COS analysis is of necessity directed at determining the cost imposed by a rate class on the system rather than at determining the cost imposed by individual customers within each classification. The cost responsibility of a specific, individual consumer may or may not be entirely consistent with the cost allocations made to his assigned consumer classification.

Third, accurate demand characteristics and load factor data for individual customer classes are often unavailable. Capacity allocations must therefore be made on the basis of estimates or "typical" data. These assumptions or estimates can have an effect on the end results.

Fourth, a COS analysis does not address itself to many of the other legitimate objectives of rate design such as member acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the cooperative. In addition, it does not recognize the need to keep each rate schedule competitive, in as much as possible, with the corresponding rate schedule of neighboring utilities or the need to keep the rate structure simple so that it is easily administered and understood by members.

With the above limitations in mind, a COS study can provide a useful guideline for assigning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a manner which avoids unjustifiable price discrimination. The study also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail members.

Q. Explain the general procedure for conducting a COS study.

A. The basic procedure used to determine the cost responsibility of each consumer classification is as follows:

Step 1 - Classify the plant account records into basic cost causative categories.

Step 2 - Classify the Test Year expenses and margin requirement into the same cost causative categories.

Step 3 - Develop allocation factors for each rate class.

Step 4 - Allocate costs to the various rate classes using the class allocation factors developed for each cost causative category.

In this regard, it is important to note that Dakota Electric has used the same COS model that was approved in our last rate case, with refinements to 1) account for a change in wholesale rates and 2) implement use of the minimum size method as ordered by the Commission in our last rate case.

Q. What do you mean by cost causative categories?

A. Plant investments, Test Year expenses and margin requirement are classified into the following cost causative categories:

1. Direct - Costs which are directly attributable to one specific customer classification. Expense associated with security and street lighting is an example of a Direct Expense.
2. Consumer - Costs that are the result of the number and location of each member and which do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses perhaps best illustrate this type of expense. In addition, a portion of distribution expenses is categorized using the results of the minimum size analysis.
3. Capacity - Costs which result from providing and maintaining in readiness for operation facilities required to meet the peak demand whether it be the system peak, circuit peak or individual member service peak. Much of the expense of operating and maintaining a three phase backbone feeder would generally fall within this category as would the Demand Charge in the purchased power rate.
4. Energy - Costs which are related to the amount of energy used. The major item in this category is the Energy Charge in the purchased power rate.

Each of these general cost causative categories is further subdivided as follows:

Direct	**Consumer**	**Capacity**	**Energy**
As Assigned		Power Supply	Power Supply
		Distribution Substation	
	Primary Line	Primary Line	
	Line Transformer	Line Transformer	
	Secondary & Service		
	Meter		
	Customer Accounting		

Q. Could you briefly explain the methodology used in assigning plant accounts to cost causative categories?

A. The cost causative classification of the various electric plant accounts is presented in pages 4 and 5 of Exhibit__(DEA-3). The methodology used in assigning the plant accounts to the cost causative categories is discussed as follows:

1. Intangible Plant (Acct. 301 to 303) - The Intangible Plant accounts were prorated to the cost categories in the same relationship as the distribution plant allocations.
2. Land, Structures, Station and Battery (Accts. 360 to 363) - The Land and Land Rights, Structures and Improvements, Station Equipment, and Battery accounts were classified as capacity related since the facilities represented by the investment are generally dictated by capacity considerations.
3. Primary Line and Devices (Accts. 364, 365, 366, 367) - Assignment of the Primary Line and Device accounts was based on results of the "Minimum Size Method" to determine the consumer component share. A narrative and calculation of the minimum size method is provided in Workpaper 21. The remaining amount was then assigned to the capacity component.
4. Line Transformers (Acct. 368) - Classification of the Line Transformer account was approached in similar fashion using the "Minimum Size Method." (See Workpaper 21.) Again, it was reasoned that there exists a certain minimum

transformer investment required to provide basic service to each consumer independent of energy usage or capacity requirements. This cost is assigned to the consumer component, while the remaining investment is considered capacity related.

5. Services and Meters (Accts. 369 and 370) - Because the investment in Services and Meters is basically independent of usage level, it was assigned entirely to the customer component.
6. Consumer Premise (Acct. 371) - The investment in installations on Consumer's Premises was assigned to Primary Line.
7. Street Lighting (Acct. 373) - Investment in street or security lighting facilities was assigned directly to the Lighting Class.
8. General Plant Accounts (Accts. 389 to 399) - The General Plant accounts were assigned to the cost causative categories in the same relationship as the total distribution plant allocations. Because the assignment of the general plant investment has minimal effect on the classification of Test Year expenses, which ultimately is used to determine class COS responsibility, a more detailed analysis of general plant investment was not warranted.

Q. Explain how revenue requirements were classified.

A. The Operating Statement for the Test Year forms the basis for the COS analysis. Actual expenses by account for the historical 12-month period were used to establish the pattern of the Test Year cost breakdown to the various accounts.

The various components of the revenue requirements were classified to the four basic cost causative categories as presented on pages 8 through 13 of Exhibit__(DEA-3). The factors used in the expense classification are summarized in pages 14 through 17 of Exhibit__(DEA-3). The methodology and rationale for that methodology is discussed below:

1. <u>Purchased Power (Acct. 555)</u> - The Demand and Energy Charge portions of the cost of Purchased Power were assigned to the capacity and energy components, respectively.
2. <u>Distribution Operation and Maintenance (Accts. 580 - 598)</u> - Distribution expense accounts that are related to specific plant accounts (Accts. 582, 583, 584, 585, 586, 591, 592, 593, 594, 595, 596 and 597) were classified in proportion to the corresponding plant accounts. These expenses result from operating and maintaining the distribution plant and thus may be considered plant related. The remaining distribution expense accounts (Accts. 580, 581, 587, 588, 589, 590 and 598) were prorated on the basis of the sum of the previously assigned distribution expense accounts. These accounts basically represent overhead or general distribution expenses.
3. <u>Consumer Accounting (Accts. 901 - 905)</u> - Consumer Accounting expenses were assigned in total to the consumer component since this expense is basically independent of energy usage or capacity requirements. Instead, these accounts are related to the number of consumers.
4. <u>Consumer Service and Information and Sales (Accts. 907 - 916)</u> - Consumer Service and Information and Sales expenses are also considered consumer related expenses.
5. <u>Administrative and General (Accts. 920 - 932)</u> - Administrative and General (A&G) expenses are common costs for which there exists no obvious relationship to the functional categories. Thus, we have assigned 10 percent of these expenses

to the power supply function and the remainder in proportion to the total of all other expenses without power supply.

6. Depreciation and Amortization (Accts. 403 - 407) - Depreciation and Amortization expense was allocated in proportion to the net plant account assignments.
7. Property Taxes (Acct. 408) - Property Taxes were assigned in proportion to the plant account assignments.
8. Other Taxes, Other Interest, and Other Deductions - Other Taxes, Other Interest, and Other Deductions were assigned in a manner similar to the A&G Accounts.
9. Net Operating Income (Margin Requirement) - Since margin is comprised of interest expense and return on equity, both related to plant investment, it is reasonable to classify this cost in proportion to the net plant assignments. This approach most nearly parallels the method used to determine target margin requirements (i.e., rate base - ROR method).

Q. Discuss the allocation of costs to rate classes.

A. The allocation of the revenue requirement to each consumer classification is presented in pages 20 to 22 of Exhibit__(DEA-3). The allocations are based on various allocation factors that reflect certain cost causative drivers as discussed below:

1. Direct Cost Allocation

   Costs specifically associated with street or security lighting facilities (investment and O&M) directly assigned to the Lighting Class are an example of a possible direct cost allocation.

2. Consumer Costs Allocations

   Generally speaking, consumer related costs were allocated to the various classes on the basis of the total number of consumers in each class. However, several adjustments were made in the general allocation procedure to reflect differences in the cost of providing basic service. Weighting factors were developed on page 23 of Exhibit__(DEA-3) to recognize the higher cost of three phase service versus standard single phase service for each subcategory of consumer related cost. A "weighting factor" of 0.02 was used to allocate the consumer expense related to providing basic service to an individual security or street light. Because these lights make use of facilities and services which have been primarily provided for under other rate schedules, it may be argued that it costs no more to prepare a bill for a consumer with a security light than for one without. However, it seems only fair that the lighting classes should be required to pay at least a token portion of the consumer related expense, hence the 0.02 weighting factor.

3. Capacity Cost Allocations

Three different allocation factors were developed for the capacity component. (See pages 24 to 40 of Exhibit__(DEA-3) for the development of class demands):

a. Line transformer capacity related costs were allocated in accordance with the estimated average monthly, undiversified non-coincidental peak demand of each consumer in each class as this definition of demand most closely approximates transformer capacity requirements.

b. Primary line capacity allocated costs were allocated using the Average and Excess Demand Method based on the average monthly coincidental demand for each class (not necessarily coincidental with the system). Distribution system capacity related costs are a function not only of the system peak, but also the individual circuit and even consumer peak demand. The Average and Excess Demand Method gives recognition to the average demand imposed on the system by each class as well as the average monthly peak demand of the class (non-coincidental) and prevents any class from getting a “free ride” from a capacity standpoint.

c. Purchased power Demand Charges and distribution substation capacity costs were allocated in accordance with the average monthly coincidental class demands.

4. Energy Cost Allocations

Energy related costs were allocated on the basis of total energy sales in each rate class.

Allocation factors for each category are developed in pages 41 to 42 of Exhibit__(DEA-3).

Q. Please summarize the results of the COS study performed for Dakota Electric.

A. Results obtained from the COS analysis are summarized in Tables 6, 7 and 8. Table 6 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 6 Cost of Service Summary				
Rate Class	**Revenue Present Rates**[5]	**Revenue Requirement**	**Increase (Decrease)**	
			Amount	**Percent**[6]
	($)	($)	($)	(%)
Residential & Farm (31,32,53)	112,384,414	115,576,812	3,192,398	2.85
Small General Service (41)	6,674,522	7,171,338	496,817	7.47
Irrigation (36)	977,226	997,009	19,783	2.03
General Service (46,54)	47,909,060	47,749,413	(159,647)	-0.33
C&I Interruptible (70,71)	26,594,877	27,212,425	617,548	2.33
Lighting	1,999,160	2,021,495	22,335	1.12
			Total System	2.11

Table 7 shows a breakdown of the COS by cost category for each class.

Table 7 Cost Allocation Summary				
Rate Class	**Cost Category**			
	Power Supply	**Transmission**	**Distribution**	**Total**
	($)	($)	($)	($)
Residential & Farm (31,32,53)	65,388,335	13,763,889	36,424,587	115,576,812
Small General Service (41)	3,921,253	834,934	2,415,151	7,171,338
Irrigation (36)	555,696	9,566	431,747	997,009
General Service (46,54)	34,247,758	7,102,136	6,399,518	47,749,413
Interruptible Service (70,71)	22,056,995	868,458	4,286,972	27,212,425
Street and Security Lighting	639,202	117,367	1,264,926	2,021,495
Total	126,809,240	22,696,351	51,222,901	200,728,492

5 Includes an allocated share of Other Operating Revenue.

6 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

Table 8 provides total costs by class expressed in terms of $ per customer per month (consumer component) and ¢ per kWh (capacity and energy components).

Table 8 Unit Cost Summary			
Rate Class	Consumer Unit Cost	Demand Unit Cost	Energy Unit Cost
	($/cust.mo.)	(¢/kWh)	(¢/kWh)
Residential & Farm (31,32,53)	23.39	5.03	5.05
Small General Service (41)	33.28	4.90	5.05
Irrigation (36)	62.56	1.87	5.05
General Service (46,54)	69.45	5.09	5.05
Interruptible Service (70,71)	188.92	1.08	5.05
Street and Security Lighting	0.47	3.64	4.73

Q. Is any other cost analysis included in this filing besides the class COS study?

A. Yes, several other cost analyses are included in my exhibits as follows:

Exhibit__(DEA-4)	Load Management Cost Analysis
Exhibit__(DEA-7)	Monthly Fixed Charge Analysis
Exhibit__(DEA-8)	Coincidental Demand Charges
Exhibit__(DEA-10)	Special Fees and Charges
Exhibit__(DEA-11)	Line Extension Analysis
Exhibit__(DEA-12)	Base Calculations for Resource and Tax Adjustment
Exhibit__(DEA-13)	Air Conditioning Analysis
Exhibit__(DEA-14)	Standby Rate Analysis
Exhibit__(DEA-15)	Electric Vehicle Rate Analysis
Exhibit__(DEA-16)	Residential TOU Analysis – Proposed Schedule 55

Q. Please explain the load management cost analysis.

A. The load management cost analysis, shown in Exhibit__(DEA-4), presents the costs to provide service to Schedules 49, 51, and 52. These costs include meter and control unit, wholesale power costs, line losses, allocated distribution costs, and margin. In the case of storage service, the cost is calculated at 4.39¢ per kWh, while the cost for interruptible service is 5.46¢ per kWh. The cost for geothermal heat pump service is calculated at

10.3¢ per kWh. This cost analysis will form the basis for rate recommendations for Schedules 49, 51 and 52 described later in my testimony.

Q. Explain the exhibit that calculates monthly fixed charge costs.

A. Exhibit__(DEA-7) calculates the monthly costs that should be applied in the monthly fixed charge of retail rates. This exhibit first identifies the "customer" related costs allocated to each class in the cost of service study. While such costs have been allocated based on number of consumers, not all of these costs may be appropriate for recovery in the monthly fixed charge. As Dakota Electric testified in our last general rate case, we believe it is appropriate for the monthly fixed charge to recover costs we incur to stand ready to provide electric service, excluding costs for primary line. Such costs to be included in the monthly fixed charge include the monthly cost of a transformer, meter and service, customer accounting, as well as taxes and margin associated with plant costs proposed for recovery in the monthly fixed charge. The monthly fixed costs identified for recovery in this analysis are as follows:

Residential	$11.65
Small General	$18.94
Irrigation	$44.09
General	$51.24
C&I Interruptible	$167.66

This cost analysis will form the basis for rate recommendations described later in my testimony.

Q. Discuss the calculation of coincidental Demand Charges shown in Exhibit__(DEA-8).

A. The calculation of Coincidental Demand Charges reflects the wholesale demand-related charges Dakota Electric experiences from Great River Energy adjusted for distribution line loss. These calculations allow us to determine the summer, winter and other months' retail Coincident Demand Charges for the partial interruptible option and full interruptible option for Dakota Electric's Schedules 70 and 71.

Q. Explain the analysis for special fees and charges.

A. Exhibit__(DEA-10) presents an analysis of Dakota Electric's costs associated with special fees and charges. This exhibit calculates the labor, benefits, vehicles and other expenses associated with each special fee and charge. The results of this analysis will be used to update Dakota Electric's special fees and charges.

Q. Explain the line extension analysis.

A. Exhibit__(DEA-11) presents the costs of actual line extension project costs and charges. This exhibit also identifies the amount of plant investment Dakota Electric recovers through base rates for these line extensions. The plant investment amounts on a per kWh and per kW basis from this exhibit will be applied to commercial line extensions.

Looking at recovery for individual residential line extensions, Exhibit__(DEA-11) shows that Dakota Electric's base rates for residential members recover about 56 feet of line extension costs. To moderate a change from the present 100 base footage allowance applied to line extension charges that were established in our last rate case, we propose to revise the base footage allowance for line extensions to 75 feet. For extensions beyond this base footage allowance, Dakota Electric proposes to charge $8.30 per foot. In addition, we presently charge an additional $200.00 flat fee for all individual residential extensions. We propose to increase the flat fee to $500.00 for the first 75 feet of an extension applicable to all individual residential extensions. This flat fee increase will provide additional revenue to cover more of the fixed costs associated with transformer and connection costs not otherwise recovered in base rates. We note that while these line extension costs are proposed to increase, the amount of increase is below our extension costs not being recovered in base rates. Dakota Electric anticipates making continued incremental increases to individual residential line extension provisions in future rate case proceedings.

Finally, the Order in our last rate case requires Dakota Electric to note any change in the annual number of individual residential line extensions. The annual number of individual residential line extensions is less than the number of extensions in our last rate case. In the past 5 years the annual number of residential extensions has varied from 6 to 16.

Q. Have you calculated new base factors for Dakota Electric's Resource & Tax Adjustment (RTA)?

A. Yes. Exhibit__(DEA-12) presents the calculation of RTA base components for cost of power, conservation and DSM expenditures, and property tax recovery. These new base components will be applied with the implementation of final rates.

Q. Please describe the calculation of power cost bases.

A. We have calculated several different power cost bases that track differences in wholesale power costs associated with specific retail rates. The calculation begins with an identification of an Energy Cost Adjustment (ECA) base. This ECA base relates to retail interruptible service that Dakota Electric provides to C & I members under interruptible service Schedules 70 and 71. This ECA base also applies to interruptible irrigation service provided under Schedule 36. (We note that firm irrigation service under Schedule 36 will be subject to the firm Power Cost Adjustment (PCA) base as described below.) The average wholesale energy cost per kWh applicable to the Energy Cost Adjustment base equals $0.0497 per kWh sold.

The next part of this exhibit calculates weighted power cost bases for Dakota Electric's load management rates including Schedules 51 and 52. For each rate schedule, we have calculated a weighted average wholesale power cost reflecting the relative purchase of water heating and space heating service under each schedule. Schedule 51 has a weighted power cost base per kWh sold of $0.0200. Schedule 52 has a weighted power cost base per kWh sold of $0.0305.

Next we calculate the power cost base for rate Schedule 49, geothermal service. The base for this service includes the Cooperative's system average wholesale cost for energy, capacity, transmission, and ancillary service cost on a per kWh basis. The resulting Schedule 49 power cost base per kWh sold is $0.0775.

Finally, this exhibit calculates the Power Cost Adjustment (PCA) base applicable to Dakota Electric's remaining firm service rate schedules. This calculation begins with the Cooperative's total wholesale power cost, from which we subtract ECA power costs, Rate 51 power costs, Rate 52 power costs, Rate 49 power costs, and wholesale power cost pass-throughs for Wellspring and standby service. The result is a PCA base per kWh sold for Dakota Electric's firm service rate schedules of $0.0899.

Q. Explain the Exhibit that evaluates cycled air conditioning.

A. Exhibit__(DEA-13) calculates the wholesale power cost savings achieved through cycling central air conditioners. Dakota Electric's cycled air conditioning program, in coordination with Great River Energy, provides for load control of central air conditioners typically during times of high demand. Air conditioners are controlled, or cycled, through fifteen minute on and fifteen minute off cycles during the respective control period. This exhibit calculates a diversified demand reduction for a typical controlled air conditioning unit. Based on a comparison of analysis results from our 2009 rate case and the present Test Year, Dakota Electric recommends a $1.00 increase in the savings available to members participating in this program. That is, the present $12.00 per month credit in the months of June, July, and August is recommended to increase to a $13.00 per month credit, with a corresponding increase in the energy credit for those units that are separately metered and an increase in the per ton credit for commercial units.

Q. Please explain the Standby Analysis.

A. Exhibit__(DEA-14) calculates the primary and secondary distribution reservation fees for Standby Service. These costs are based on allocated costs to Dakota Electric's General Service Schedule 46, which corresponds to the size and type of customers who would likely receive such standby service. In fact, the one standby member that Dakota Electric serves is of a size that would normally receive service under Schedule 46.

Q. Please explain the Electric Vehicle Rate Analysis.

A. Exhibit__(DEA-15) updates the cost analysis that Dakota Electric submitted to the Commission when we proposed this service. The update specifically relates to Test Year wholesale power supply costs. While Dakota Electric is presently within the two year "pilot" phase of this rate, we believe it is appropriate to provide this analysis within the context of our general rate case.

Q. Please explain the Residential TOU Analysis for the proposed new Schedule 55.

A. Exhibit__(DEA-16) presents an analysis of costs and development of rate design for a new proposed residential time of use rate. Page 1 of this exhibit identifies wholesale power and distribution costs based on the cost of service study results for the residential class. Page 2 assigns these costs to respective cost components and time periods. Page 3 estimates billing units, on a total residential class basis, for the billing periods proposed for this new schedule. Page 4 develops rates for each billing component using the cost assignments from page 2. Finally, page 5 presents a graphic depiction of the billing periods for this proposed schedule.

VI. RATE DESIGN

Various tables showing the results of the COS analysis are useful in discussing the design and evaluation of Dakota Electric's rates. These tables, which have been previously presented, are listed below:

Table	Description
Table 6	Cost of Service Summary
Table 7	Cost Allocation Summary
Table 8	Unit Cost Summary

Q. What objectives have you considered while developing proposed rate changes?

A. There are many legitimate objectives that influence the design of rates. Some of the more important ones are as follows:

1. The proposed rates must develop the requisite total revenue.
2. The proposed rates should reflect the cost of providing service. No class or subclass should subsidize or be subsidized by another.
3. The rate schedules should be simple and concise to facilitate consumer acceptance and administration.
4. Abrupt departures from historical rate practices and levels should be avoided.
5. The rate structure should be acceptable to the membership.

6. Where there is a possibility of a consumer being eligible to receive service under more than one rate schedule, the transition should be made as smoothly as possible.
7. The rates should promote the efficient use of energy and system capacity.
8. Whenever possible, the rate schedule should be competitive with those of neighboring utilities and alternative energy sources.

It is generally not possible to fully accomplish all of the above objectives in developing rate schedules. Compromises based on judgment reflecting the policy of the Cooperative must be made.

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as 1) the need to avoid abrupt changes and 2) the desire to achieve member-consumer acceptance also came into play. Thus, the dollar and percentage increase or decrease for each class as shown in Table 6 were tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Summarize the revenue impact of your proposed rates.

A. The rate design recommendations for the rate schedules contained and discussed herein result in an approximate $4,135,000 revenue increase. (We note that additional annual revenue will be provided by proposed changes to special fees and charges and from residential line extensions.) Table 9 presents a comparison of the Present and Proposed Rates by service schedule.

Table 9
Comparison of Revenue
Present and Proposed Rates

(a)	(b)	(c)	(d)	(e)	(f)
		Revenue	**Revenue**	**Increase (Decrease)**	
Line No.	**Rate Class**	**Present Rates** ($)	**Proposed Rates** ($)	**Amount** ($)	**Percent** (%)
1	Residential & Farm Service (31)	113,330,908	116,469,554	3,138,646	2.77
2	Residential & Farm Demand Control (32)	48,617	50,073	1,456	2.99
3	Electric Vehicle (33)	1,037	989	(48)	(4.63)
4	Irrigation Service (36) Firm	69,220	72,307	3,087	4.46
5	Irrigation Service (36) Interruptible	904,565	920,980	16,415	1.81
6	Small General Service (41)	6,767,752	7,111,447	343,695	5.08
7	Security Lighting Service (44)	158,673	160,230	1,557	0.98
8	Street Lighting Service (44-2)	494,127	499,146	5,019	1.02
9	Street Lighting System (44-1)	66,583	67,243	660	0.99
10	Custom Residential Street Lighting (44-3)	1,272,737	1,285,813	13,076	1.03
11	Low Wattage Unmetered Service (45)	5,184	6,480	1,296	25.00
12	General Service (46)	47,284,619	47,313,119	28,500	0.06
13	Municipal Civil Defense Sirens (47)	3,900	3,900	-	-
14	Geothermal Heat Pump (49)	32,921	36,406	3,485	10.59
15	Controlled Energy Storage (51)	404,057	419,307	15,250	3.77
16	Controlled Interruptible Service (52)	2,481,912	2,575,568	93,656	3.77
17	Residential & Farm Time of Day (53)	31,553	32,474	921	2.92
18	General Service Time of Day (54)	455,726	446,035	(9,691)	(2.13)
19	Standby Service (60)	56,550	60,990	4,440	7.85
20	Full Interruptible Service (70)	24,579,461	25,096,828	517,367	2.10
21	Partial Interruptible Service (71)	1,921,760	2,003,538	81,778	4.26
22	Cycled Air Conditioning Service (80)	(1,539,168)	(1,664,599)	(125,431)	8.15

Q. Provide an overview of your approach to proposed changes in monthly fixed charges.

A. Exhibit__(DEA-7) identifies the cost basis for the proposed monthly fixed charges and was described above. Using these results, Dakota Electric proposes to increase the monthly fixed charge for residential service and small general service such that we may attain the desired cost level in two steps – one step in this rate case and the another step in our next future rate case. For the other rate schedules, we propose increasing the monthly fixed charge by a percentage similar to the residential monthly fixed charge increase. The proposed monthly fixed charge changes 1) provide a more appropriate recovery of costs through this rate component, 2) reduce the amount of such costs that are otherwise recovered in volumetric charges, 3) align with similar charges the Commission has approved for neighboring utilities, and 4) make reasonable progress in this rate case. We note that a smaller increase in the monthly fixed charge could result in taking 20 years or more to reach the appropriate cost recovery level for this component – based on the more recent approximate five year cycle for Dakota Electric rate cases.

Q. Please describe the proposed rates.

A. Discussion of each of the proposed rates follows:

Residential & Farm Service (31)

The COS study shows the need to increase revenue from Residential & Farm (Schedules 31, 32 and 53) of about $3,192,000 or a 2.85 percent increase (see Table 6) over revenue from present rates. Dakota Electric is proposing a slightly lower increase for residential members. We propose to increase the monthly fixed charge from the present $8.00 to $10.00. The present summer Energy Charge of $0.11544 per kWh ($0.12864 per kWh including the RTA) is proposed to increase to $0.1296 per kWh for the summer months of June, July and August. The proposed Energy Charge for all other months will increase from $0.10144 per kWh ($0.11464 per kWh including the RTA) to $0.1156 per kWh. These proposed rates reflecting a "zeroing" of the present RTA and result in an increase to the Schedule 31 class of approximately 2.77 percent.

Table 10 Comparison of Present and Proposed Residential & Farm Service (31)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$8.00/month	$10.00 /month
Energy Charge		
Summer Months	$0.11544/kWh	$0.1296/kWh
Other Months	$0.10144/kWh	$0.1156/kWh
Average Charge		
RTA Charge	$0.0132/kWh	$0.0000/kWh

Residential & Farm Demand Control (32)

As previously noted, the COS study generally shows a required revenue increase from Residential members of about 2.85 percent. Accordingly, we recommend that the monthly Fixed Charge be increased from $11.00 to $13.00. We further propose to continue the seasonality in this rate structure through the Demand Charge by increasing the summer Demand Charge from $12.90 per kW per month to $14.70 and the demand rate for all other months from $9.30 per kW to $11.10 per kW. We propose to increase the Energy Charge from the present tariff amount of $0.0648 per kWh ($0.078 per kWh including the RTA) to $0.0756 per kWh. These proposed rates result in a revenue increase of about 2.99 percent for this rate schedule.

Table 11 Comparison of Present and Proposed Residential & Farm Demand Control (32)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$11.00/month	$13.00/month
Demand Charge		
Summer Months	$12.90/kW	$14.70/kW
Other Months	$9.30/kW	$11.10/kW
Energy Charge	$0.0648/kWh	$0.0756/kWh
Average Charge		
RTA Charge	$0.0132	$0.0000

Electric Vehicle - Residential (33)

Dakota Electric received Commission approval to implement a pilot residential electric vehicle service in Docket No. E-111/M-12-874. This service (also referred to as Schedule EV-1) provides our residential members with an additional option for charging the batteries in their electric vehicle. Dakota Electric proposes to update the rates for this service based on the Test Year wholesale power cost analysis in Exhibit__(DEA-15). The comparison of present and proposed rates is shown in Table 12 below.

Table 12
Comparison of Present and Proposed
Residential Electric Vehicle Service (33)

Description	Present Rate	Proposed Rate
Energy Charges:		
Off-Peak	$0.0585/kWh	$0.0674/kWh
On-Peak	$0.3785/kWh	$0.4144/kWh
Other	Schedule 31	Schedule 31
RTA Charge	$0.0132/kWh	$0.0000/kWh

Irrigation Service (36)

The cost of service study shows the need to increase revenues from irrigation service $19,783 or about 2.03%. The firm service irrigation rate structure presently includes a monthly fixed charge of $24 per month that is applied every month throughout the calendar year. We propose increasing this monthly fixed charge to $30 per month. The seasonal component for this firm service is incorporated in the Demand Charge with a present summer month Demand Charge of $23.80 which we propose to increase to $26.35. The $18.90 per kW per month Demand Charge in the winter months is proposed to increase to $20.95 per kW, and the $14.00 per kW Demand Charge in the spring and fall months is proposed to increase to $15.50 per kW. The present Energy Charge of $0.04767 per kWh ($0.06067 per kWh including the RTA) for all energy consumed throughout the year is proposed to change to $0.0500 per kWh.

Like the firm irrigation rate, the controlled irrigation rate will include a monthly fixed charge of $30.00 per month that will be applied during all months throughout the calendar year. Since Dakota Electric does not incur any wholesale capacity costs associated with irrigation customers on the controlled rate, the demand charge will be increased from the present $4.05 per kW to $4.55 per kW to recover distribution costs. (Since there is no seasonality in the wholesale power cost associated with controlled irrigation, the controlled irrigation rate does not incorporate any seasonality.) Finally, the proposed energy rate for controlled irrigation service will be the same $0.0500 per kWh proposed for firm irrigation service.

Table 13
Comparison of Present and Proposed
Firm Irrigation Service (36)

Firm Service		Present	Proposed
Fixed Charge	@	$24.00/month	$30.00 /month
Demand Charge			
Summer	@	$23.80/ kW/month	$26.35/kW/month
Winter	@	$18.90/ kW/month	$20.95/kW/month
Other	@	$14.00/ kW/month	$15.50/kW/month
Energy Charge	@	$0.04767/kWh	$0.0500/kWh
RTA Charge	@	$0.0130/kWh	$0.0000/kWh

Table 14
Comparison of Present and Proposed
Interruptible Irrigation Service (36)

Interruptible Service		Present	Proposed
Fixed Charge	@	$24.00/month	$30.00 /month
Demand Charge	@	$4.05/ kW/month	$4.55/kW/month
Energy Charge	@	$0.04767/kWh	$0.0500/kWh
RTA Charge	@	$0.0061/kWh	$0.0000/kWh

Small General Service (41)

The COS study shows the need to increase revenues from the Small General Service class in the amount of $497,000 or 7.47 percent. Dakota Electric proposes a more moderate overall revenue increase accomplished by increasing the monthly Fixed Charge for Small General Service from the present $10.00 per month to $14.00 per month. The present Energy Charge of $0.11363 per kWh ($0.12673 per kWh including the RTA) in the summer months of June, July and August is proposed to increase to $0.1290 per kWh and the present and the $0.09963 per kWh ($0.11273 per kWh including the RTA) Energy Charge during all other months is proposed to increase to $0.1150 per kWh. These proposed rates result in a revenue increase of about 5.08 percent for this rate schedule.

Table 15
Comparison of Present and Proposed
Small General Service (41)

Description	Present Rate	Proposed Rate
Fixed Charge	$10.00/month	$14.00/month
Energy Charge		
Summer Months	$0.11363/kWh	$0.1290/kWh
Other Months	$0.09963/kWh	$0.1150/kWh
RTA Charge	$0.0131/kWh	$0.0000/kWh

General Service (46)

While the cost of service study shows a slight decrease of about 0.33 percent is justified for the General Service rate schedule, we are proposing a very slight increase in revenue from this rate schedule.

The present General Service Schedule 46 includes a monthly Fixed Charge of $28.00, which we propose to increase to $34.00. The Demand Charge in the summer months of June, July and August is proposed to increase from $11.75 per kW to $12.25 per kW.

The Demand Charge during the remaining months is proposed to increase from $8.65 per kW to $9.15 per kW.

The proposed Energy Charge reflects load characteristics of customers on a monthly basis. This energy structure, commonly referred to as an “hours-use demand rate,” is based on the amount of energy that a member uses each month <u>in relation</u> to the member’s non-coincident demand. That is, this energy rate is load-factor sensitive. The present energy rate for the first 200 kWh of energy consumption per kW of demand is $0.06637 per kWh ($0.07937 per kWh including the RTA) and is proposed to be $0.0775 per kWh. The next 200 kWh of energy consumption per kW of demand presently at $0.05637 per kWh ($0.06937 per kWh including the RTA) is proposed to increase to $0.0675 per kWh. All energy consumption above 400 kWh per kW of demand presently at $0.04637 per kWh ($0.05937 per kWh including the RTA) is proposed to increase to $0.0575 per kWh.

Dakota Electric will continue to offer primary voltage discounts for members presently receiving primary service. The proposed General Service Schedule 46 rates result in an annual revenue increase of about 0.06 percent.

Table 16
Comparison of Present and Proposed
General Service (46) Rates

Description	Present Rate	Proposed Rate
Fixed Charge	$28.00/month	$34.00/month
Demand Charge		
Summer Months	$11.75/kWh	$12.25/kWh
Other Months	$8.65/kWh	$9.15/kWh
Energy Charge		
First 200 kWh/kW	$0.06637/kWh	$0.0775/kWh
Next 200 kWh/kW	$0.05637/kWh	$0.0675/kWh
Over 400 kWh/kW	$0.04637/kWh	$0.0575/kWh
RTA Charge	$0.0130/kWh	$0.0000/kWh
Discounts		
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%

Lighting Service (Rates 44, 44-1, 44-2, 44-3)

The COS shows a need to increase lighting revenue by about 1.12 percent. Dakota Electric proposes the following lighting rates:

Table 17
Comparison of Present and Proposed
Security Lighting Service (44)

Description	Present Rate	Proposed Rates
175 W MV	$11.96/month	$13.08/month
100 W HPS	$9.45/month	$10.11/month
150 W HPS	$11.04/month	$12.00/month
250 W HPS	$14.23/month	$15.80/month

Table 18 Comparison of Present and Proposed Security Lighting Service (44-2)		
Description	**Present Rate**	**Proposed Rates**
175 W MV	$14.11/month	$15.25/month
250 W MV	$16.59/month	$18.18/month
400 W MV	$20.78/month	$23.27/month
100 W HPS	$11.60/month	$12.29/month
150 W HPS	$13.19/month	$14.18/month
250 W HPS	$16.38/month	$17.97/month
400 W HPS	$19.92/month	$22.40/month

Table 19 Comparison of Present and Proposed Street Lighting System (44-1)		
Description	**Present Rate**	**Present Rate**
175 W MV	$9.44/month	$10.53/month
250 W MV	$11.93/month	$13.47/month
400 W MV	$16.11/month	$18.55/month
100 W HPS	$6.93/month	$7.57/month
150 W HPS	$8.53/month	$9.47/month
200 W HPS	$10.18/month	$11.42/month
250 W HPS	$11.72/month	$13.26/month
400 W HPS	$15.25/month	$17.68 /month

Table 20 Comparison of Present and Proposed Custom Residential Street Lighting (44-3)		
Description	**Present Rate**	**Proposed Rates**
175 W MV	$10.28/month	$11.38/month
50 W HPS	$6.36/month	$6.71/month
100 W HPS	$7.77/month	$8.42/month
150 W HPS	$9.36/month	$10.31/month
250 W HPS	$12.55/month	$14.10/month

Low Wattage Unmetered Service (45)

Dakota Electric proposes to increase the Low Wattage Unmetered Service Schedule 45 rate from $8.00 per month to $10.00 per month.

Table 21 Comparison of Present and Proposed Low Wattage Unmetered Service (45)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$8.00/month	$10.00/month

Municipal Civil Defense Sirens (47)

Dakota Electric is not proposing any changes in the monthly $5.00 fixed charge applicable to Municipal Civil Defense Sirens.

Table 22 Comparison of Present and Proposed Municipal Civil Defense Sirens (47)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$5.00/month	$5.00/month

Geothermal Heat Pump (49)

Dakota Electric's costs analysis for the Geothermal Heat Pump Rate is shown in Exhibit__(DEA-4). The costs for Schedule 49 include meter and control unit, wholesale power costs, line losses, allocated distribution costs, and margin. The cost for geothermal heat pump service is calculated at 10.3¢ per kWh. We propose a more moderate increase in the energy charge for this service from the present tariffed rate of 6.0¢ per kWh (8.5¢ per kWh including the RTA) to 9.4¢ per kWh. Since geothermal heat pump service is no longer offered as a special program rate through our wholesale power supplier, we also propose that this service be closed to new members.

Controlled Energy Storage (51)

Dakota Electric's cost analysis for Controlled Energy Storage is shown in Exhibit__(DEA-4). The cost for Controlled Energy Storage service is calculated at 4.39¢ per kWh. We propose an increase in the Energy Charge for this service from the present $0.040 per kWh ($0.0424 per kWh including the RTA) to $0.044 per kWh. This represents an increase of approximately 3.77 percent for this service.

Table 23
Comparison of Present and Proposed
Controlled Energy Storage (51)

Description	Present Rate	Proposed Rate
Net Energy Charge	$0.0400/kWh	$0.0440/kWh

Controlled Interruptible Service (52)

A cost analysis for Controlled Interruptible Service is shown in Exhibit__(DEA-4). The cost for Controlled Interruptible service is calculated at 5.46¢ per kWh. Dakota Electric proposes an increase in the rate for this service from the present energy rate of $0.048 per kWh ($0.053 per kWh including the RTA) to a proposed energy rate of $0.055 per kWh. This represents a 3.77 percent increase.

Table 24
Comparison of Present and Proposed
Controlled Interruptible Service (52)

Description	Present Rate	Proposed Rate
Net Energy Charge	$0.0480/kWh	$0.0550/kWh

Residential & Farm Time of Day (53)

The COS for Residential & Farm Time of Day service was incorporated in the COS study with the Residential & Farm Service Schedule 31. Since the COS for these classes is similar, we are proposing a similar revenue increase for Schedule 53. This revenue increase will be achieved by increasing the monthly Fixed Charge from the present $11.00 to $13.00. The present summer Peak Period Energy Charge of $0.1600 per kWh ($0.1732 per kWh including the RTA) will be increased to $0.1860 per kWh and the present other months Peak Period Energy Charge of $0.1460 per kWh ($0.1592 per kWh including the RTA) will be increased to $0.1720 per kWh. The Off-Peak Energy Charge will be changed from $0.0825 per kWh ($0.0957 per kWh including the RTA) to $0.0930 per kWh. These proposed changes result in an overall increase of about 2.92 percent.

Table 25
Comparison of Present and Proposed
Residential & Farm Time of Day (53)

Description	Present Rate	Proposed Rate
Fixed Charge	$11.00/month	$13.00/month
Energy Charges		
Peak Period:		
Summer	$0.1600/kWh	$0.1860/kWh
Other	$0.1460/kWh	$0.1720/kWh
Off-Peak	$0.0825/kWh	$0.0930/kWh
RTA Charge	$0.0132/kWh	$0.0000/kWh

General Service Time of Day (54)

Dakota Electric proposes to realign component rates for Schedule 54 to track changes to other similar rate schedules. We propose to increase the monthly Fixed Charge for Rate 54 from the present $30.00 to $36.00. The Peak Period Demand Charge will be changed to $24.85 per kW in the summer months (June, July and August), $18.95 per kW in the winter months (December, January and February) and $13.00 per kW during all other months. The Maximum Demand Charge of $4.30 per kW will be increased to $4.75 per kW. The Energy Charge of $0.4394 per kWh ($0.05694 per kWh including the RTA) will be changed to $0.0500 per kWh. This proposed rate design results in a revenue decrease of about 2.13 percent for this rate schedule.

Table 26
Comparison of Present and Proposed
General Service Time of Day Service (54)

Description	Present Rate	Proposed Rate
Fixed Charge	$30.00/month	$36.00/month
Demand Charges		
Peak Period:		
Summer Months	$21.70/kW/month	$24.85/kW/month
Winter Months	$16.30/kW/month	$18.95/kW/month
Other Months	$10.95/kW/month	$13.00/kW/month
Maximum	$4.30/kW	$4.75/kW
Energy Charge	$0.04394/kWh	$0.0500 /kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	$0.0130/kWh	$0.0000/kWh

Residential & Farm Time of Day (55) - NEW

Dakota Electric is proposing to add a new Residential & Farm Time of Day rate that we are designating Schedule 55. Dakota Electric will continue to offer our present Schedule 53 service. The proposed new Schedule 55 offers an alternative time-based rate design with periods as follows:

Peak Periods	4:00 p.m. to 11:00 p.m., excluding holidays and weekends
Intermediate Period	8:00 a.m. to 4:00 p.m., excluding holidays and weekends
Off-Peak Period	11:00 p.m. to 8:00 a.m. Mon-Fri and all day weekends and holidays

The cost analysis and development of the proposed rates for this proposed new service is detailed in Exhibit 16 and was described above. Table 27 identifies the proposed charges for this service.

Table 27 Comparison of Present and Proposed Residential & Farm Time of Day (55)		
Description	Present Rate	Proposed Rate
Fixed Charge	NA	$13.00/month
Energy Charges		
Peak Periods:		
Summer	NA	$0.2700/kWh
Summer	NA	$0.2200/kWh
Other	NA	$0.1740/kWh
Intermediate	NA	$0.0960/kWh
Off-Peak	NA	$0.0750/kWh
RTA Charge	NA	$0.0000/kWh

Standby Service (60)

The distribution reservation fees for standby service have been analyzed in the attached Exhibit__(DEA-14). This analysis reflects the average distribution cost on a per kW basis for our General Service Schedule 46 members. Based on this analysis, we propose increasing the primary distribution reservation fee from $2.91 per kW to $3.28 per kW. The secondary distribution reservation fee is proposed to increase from $3.09 per kW to $3.51 per kW. The generation reservation fees for this service are a direct passthrough of such wholesale power standby reservation fees from Great River Energy and are updated annually as authorized in this schedule.

Interruptible Service - Full Interruptible Option (70)

The cost of service study shows a need to increase revenue from the C & I interruptible members by about 2.33 percent. To accomplish this revenue increase, we propose increasing the monthly Fixed Charge from $80.00 to $110.00 per month. Coincidental Demand Charges are proposed at $24.85 per kW in the summer months, $18.95 per kW in the winter months and $13.00 per kW during all other months. The Non-Coincidental

Demand Charge will be increased from the present $4.30 per kW to $4.75 per kW. The Energy Charge will be increased from $0.04394 per kWh ($0.04994 per kWh including the RTA) to $0.0500 per kWh.

Table 28
Comparison of Present and Proposed
Interruptible Service (Full Interruptible Option) (70)

Description	Present Rate	Proposed Rate
Fixed Charge	$80.00/month	$110.00/month
Communication Fee	$8.70/month	$8.70/month
Coinc. Demand Charge		
Summer Months	$21.70/kW/month	$24.85/kW/month
Winter Months	$16.30/kW/month	$18.95/kW/month
Other Months	$10.95/kW/month	$13.00/kW/month
Non-Coinc. Demand Charge	$4.30/kW	$4.75/kW
Energy Charge	$0.04394/kWh	$0.0500/kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	$0.0060/kWh	$0.0000/kWh

Interruptible Service - Partial Interruptible Option (71)

Dakota Electric proposes the same retail rates for Schedule 71 as Schedule 70. The difference between these two services is that Schedule 70 consumers agree to fully interrupt their load during specified load control periods. Schedule 71 members, however, agree to reduce their load during control periods but not necessarily to zero. Accordingly, these consumers will have some portion of their load on during the control periods.

Table 29 Comparison of Present and Proposed Interruptible Service (Partial Interruptible Option) (71)		
Description	**Present Rate**	**Proposed Rate**
Fixed Charge	$80.00/month	$110.00/month
Communication Fee	$8.70/month	$8.70/month
Coinc. Demand Charge		
Summer Months	$21.70/kW/month	$24.85/kW/month
Winter Months	$16.30/kW/month	$18.95/kW/month
Other Months	$10.95/kW/month	$13.00/kW/month
Non-Coinc. Demand Charge	$4.30/kW	$4.75/kW
Excess Demand	$5.00/kWh	$5.00/kWh
Energy Charge	$0.04394/kWh	$0.0500/kWh
Primary Voltage Disc.	$0.15/kW	$0.15/kW
Primary Metering Disc.	2.00%	2.00%
RTA Charge	$0.0060/kWh	$0.0000/kWh

Cycled Air Conditioning Service (80)

Dakota Electric's pricing for the four options under cycled air conditioning service reflect the savings we experience in wholesale capacity charges by members agreeing to control their air conditioners during peak periods. An analysis of wholesale power cost savings associated with cycled air conditioning is presented in Exhibit__(DEA-13). Based on this analysis, we propose an increase in the net benefit to the members participating in cycled air conditioning. The proposed rates for these options are presented below:

Table 30 Comparison of Present and Proposed Controlled Air Conditioning Service (80)		
Description	**Present Rate**	**Proposed Rate**
Option 1		
Option 2	($0.0300)/kWh	($0.0320)/kWh
Option 3	($12.00)/month	($13.00)/month
Option 4	($6.00)/ton/month	($6.50)/ton/month

Q. Have you prepared comparisons of the Present and Proposed Rates?

A. Yes, I have. Exhibit__ (DEA-6) provides several different comparisons of the present versus proposed rates as follows:

- Comparison of Present and Proposed Rates
- Comparison of Revenue under Present and Proposed Rates
- Comparison of Bills under Present and Proposed Rates for Selected Classes

Q. Is Dakota Electric proposing changes to other charges in addition to the rate schedules identified above?

A. Yes. Dakota Electric is proposing changes to its special fees and charges per occurrence as follows:

Description	Current Charge	Proposed Charge
Meter Test at Customer's Request		
Single phase	$ 75.00	$ 85.00
Three phase	$ 85.00	$ 100.00
Bad Check	$ 15.00	$ 15.00
Reconnection Charge (after disconnect, same customer)		
Self-Contained Meter		
Normal working hours	$ 45.00	$ 50.00
After hours	$120.00	$130.00
Transformer-Rated Meter		
Normal working hours	$150.00	$175.00
After hours	$270.00	$315.00
Service Charge (outside normal working hours when problem is not with DEA equipment)	$270.00	$280.00
Load Management Service Charge		
Normal working hours	$ 60.00	$ 70.00
After hours	$120.00	$140.00
Pulse Meter	$350.00	$500.00
Temporary Service		
Non-winter months	$200.00	$205.00
Winter months	$325.00	$340.00
Transfer/Connection	$ 17.50	$ 17.50

These changes are supported by the cost analysis presented in Exhibit__(DEA-10).

Q. Are there any other proposed changes?

A. As I mentioned earlier, Dakota Electric is also proposing to update its line extension charges. The present line extension policy provides a base footage allowance of 100 feet, with a $200.00 charge imposed on all individual residential line extensions plus $6.80 per foot for extensions in excess of 100 feet. Dakota Electric proposes to change individual residential line extension charges to a base footage allowance of 75 feet, with a $500.00 charge imposed on all individual residential line extensions plus $8.30 per foot for extensions in excess of 75 feet This proposed line extension charge better reflects costs recovered through base rates and helps ensure that new members are paying a more reasonable share of line extension costs while reducing any cost burden on existing ratepayers.

Q. Is Dakota Electric proposing any other rate book modifications?

A. Yes. We are proposing several clarifications to the tariff pages in Section VI – General Rules and Regulations. We are also proposing to reorder the pages in Section V – Rate Schedules. Dakota Electric has been rate regulated for over 30 years. During that time we have added many new rate schedules. It is time to bring some order to these pages.

Q. Have you prepared revised tariff pages reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit__(DEA-17) includes Dakota Electric's present rate schedules. This exhibit is followed by Exhibit__(DEA-18) that includes marked-up versions of present rate schedules showing all proposed additions and deletions. (The software used for this purpose specifically identifies text that has been deleted. Text proposed for addition is shown as underlined.) The first pages of this exhibit identify the present page numbers for Section V and the proposed new page numbers. Finally, Exhibit__(DEA-19) presents a "clean" version of proposed rate schedules. The first pages of this exhibit list the pages for Section V in the proposed new order, with reference to the existing page numbers for cross-reference.

VII. SMART METERING COMPLIANCE TESTIMONY

Q. Explain why you are submitting this compliance testimony in this proceeding.

A. On August 10, 2007, the Minnesota Public Utilities Commission (Commission or MPUC) issued an *Order Taking Action Under Federal Energy Policy Act of 2005* (Docket No. E-999/CI-06-159). In that August 10, 2007 Order the Commission stated its intention to examine individual utilities' smart metering practices in the context of rate cases.

Q. Please describe the content of this compliance testimony.

A. This compliance testimony will 1) describe the Energy Policy Act of 2005 (EPAct 05) and the issue of smart metering, 2) summarize the MPUC's smart metering findings and action in Docket No. E-999/CI-06-159, and 3) review Dakota Electric's rate offerings in relation to the smart metering standard contained in EPAct 05.

Q. Provide an overview of the Federal Energy Policy Act of 2005 (EPAct 05).

A. On August 7, 2005, the Federal Energy Policy Act of 2005 became effective. This Act covers a variety of energy related issues contained in 18 "Titles." Title XII covers electricity matters and is referred to as the "Electricity Modernization Act of 2005." Included in Title XII is Subtitle E, "Amendments to PURPA," which modifies Title I of the Public Utility Regulatory Policies Act (PURPA) of 1978. Title I of PURPA established a number of "rate design" standards (e.g., cost of service, time-of-day rates) that utilities covered under the Act were required to consider. The 2005 update of PURPA Title I requires consideration (but not necessarily adoption) of five new "rate design" standards including:

1. Net metering for distributed generation (DG);
2. Interconnection requirements for DG;
3. Smart metering and other demand-side management (DSM) initiatives;
4. Fuel diversity; and
5. Fossil fuel generation efficiency.

Q. What is "Smart Metering"?

A. Smart metering, in brief, is the ability to choose time-based rate schedules over "flat" rate schedules. Under a time-based rate schedule, the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. Despite the title of "smart metering," the focus of this standard is really about rates. A time-based rate schedule enables an electric consumer to manage energy use and cost. Examples of time-based rate schedules that may be offered under this standard include:

- Time-of-day pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year;
- Critical Peak Pricing (CPP) whereby time-of-day prices are in effect except for certain peak days;
- Real-Time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis; and
- Credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

Q. What consideration of Smart Metering is required by EPAct 05?

A. EPAct 05 requires only that covered utilities/regulatory bodies "consider" each of the standards. It does not require that the standards be adopted. A covered utility/regulatory body may:

- Accept a standard;
- Reject a standard;
- Modify a standard; or
- Defer implementation of a standard.

Title I of PURPA sets forth three purposes for implementing the rate design standards including:

1. Conservation of energy supplied by electric utilities;

2. The optimization of the efficiency of use of facilities and resources by electric utilities; and
3. Equitable rates to electric customers.

Q. How does EPAct 05 affect the MPUC?

A. The Federal Energy Policy Act of 2005 requires state regulatory bodies to consider (but not necessarily adopt) five new "rate design" standards – including smart metering and other demand-side management initiatives.

Q. Did the Commission adopt a standard on smart metering?

A. No. The Commission found on Pages 3 to 4 of its August 10, 2007, Order:

> "Having conducted the investigation required in Section 1252 (b) of the Act, the Commission finds, from an industry-wide perspective and in light of current conditions and knowledge, that it would not be appropriate at this time for electric utilities to provide and install time-based meters and communications devices for each of their customers.
>
> First, each of the utilities responding in this matter has at least partially implemented some form of time-variant rates, offering rate schedules in which price varies in relation to variations in cost at different times during the day. Such rates, however, are not often preferred by customers over standard rates. No Minnesota utility has implemented mandatory time-based rate schedules for each of its customers.
>
> Second, voluntary participation in utility programs offering time-of-use rates is generally low amongst residential customers, in large part due to the hours of the on-peak period compared to the off-peak period.

> Third, while the technology currently exists to utilize time-based billing, to require utilities to implement the technology would require for some utilities an across-the-board upgrade of meters and load management infrastructure.
>
> Fourth, the utilities requested flexibility, not a one-size-fits-all approach."

Q. What action did the Commission take on Smart Metering based on the above findings?

A. The Commission modified the smart metering standard "to include practices that achieve goals similar to smart metering, and which reflect Minnesota utilities' experiences with practices that achieve the same goals as smart metering." (MPUC Ordering Paragraph 6 at Page 5) The Commission also found it "appropriate to consult the standard, as modified to reflect Minnesota utilities' experiences, during the review of rate structures of individual utilities on an ongoing basis, during rate cases or at other appropriate times." (MPUC Ordering Paragraph 8 at Page 5)

Q. What is the goal of smart metering?

A. To rephrase the language of EPAct 05, the goal of smart metering is to enable electric consumers to manage energy use and cost through rates charged by electric utilities that vary during different time periods reflecting the variance in the utility's costs of generating and purchasing electricity at the wholesale level. This is consistent with the intent of smart metering as articulated on Page 4 of the MPUC August 10, 2007 Order stating "that utility customers should know in advance when it is important to conserve energy, and to be apprised of the effect of their energy use on individual billing as well as the system as a whole."

Q. Describe the time-based rates and demand response (load management) rates offered by Dakota Electric.

A. Dakota Electric time-based rates and demand response programs were recently described in the Cooperative's annual Smart Grid Report submitted on April 1, 2014 in Docket No. E-999/CI-08-948.

Q. What was the impetus for establishing these rates?

A. Dakota Electric's time-based rates were established in the early 1980s in response to the 1978 Public Utility Regulatory Policies Act (PURPA), which encouraged consideration and implementation of time-based rate schedules. Dakota Electric's demand response efforts were initiated in the early to mid-1980s in response to rapidly rising wholesale capacity costs. Demand response (load management) offered a significant opportunity for Dakota Electric to lower its wholesale power costs and pass these savings on to participating members.

Q. Describe the metering and communication technologies Dakota Electric has in place to facilitate these rate offerings.

A. Dakota Electric's metering and communication technologies were recently described in the Cooperative's annual Smart Grid Report submitted on April 1, 2014 in Docket No. E-999/CI-08-948.

Q. Summarize the customer response and participation in these rates.

A. The consumer response and participation in these rates was recently described in the Cooperative's annual Smart Grid Report submitted on April 1, 2014 in Docket No. E-999/CI-08-948.

Q. Does Dakota Electric provide other information to let members know when to conserve energy during times of high wholesale power costs?

A. Yes. Dakota Electric implemented a "Conservation Gauge" in 2008. The conservation gauge is featured prominently in our Web site and described in our monthly newsletter "Circuits." While Dakota Electric encourages members to save energy year-round, some days require additional actions to keep electricity use and costs down. Dakota Electric developed the conservation gauge to inform members of changes in the market price of electricity and the need for additional conservation efforts on high use days. The conservation gauge includes three settings of 1) normal, 2) peak, and 3) critical. Each setting includes descriptions of the kinds of energy savings actions members may consider to lower the consumption of energy.

Q. Do Dakota Electric's present time-based and demand response (Load Management) rates satisfy the purpose of EPAct 05 and the goal for the smart metering standard?

A. Yes.

Q. Please explain.

A. Title I of PURPA sets forth three purposes for implementing the rate design standards including:

1. Conservation of energy supplied by electric utilities;
2. The optimization of the efficiency of use of facilities and resources by electric utilities; and
3. Equitable rates to electric customers.

As discussed above, Dakota Electric's time-based rates, load management rates, and the conservation gauge have been designed and specifically implemented to achieve these three purposes. These rates lead to the conservation of energy and/or reduce the demand requirements for the cooperative both of which help control present and future costs. The load management programs in particular optimize the use of generating facilities and help avoid or defer additional construction of generating plants. Finally, since our time-based and load management rates are cost-based they provide equitable rate to consumers. Dakota Electric's time-based and load management rates also satisfy the goal of smart metering which is to enable electric consumers to manage energy use and cost through rates charged by electric utilities that vary during different time periods reflecting the variance in the utility's costs of generating and purchasing electricity at the wholesale level. This goal is supported by the conservation gauge. Dakota Electric's retail time-based and load management rates are coordinated with the wholesale rates and programs offered by Great River Energy. Dakota Electric has achieved exceptional participation in these voluntary rate offerings – especially the load management rates. These demand reductions have allowed GRE to defer construction of new generation capacity, while providing significant savings to participating and non-participating Dakota Electric customers.

VIII. SUMMARY & CONCLUSION

Q. Please summarize your testimony and requests for Commission action.

A. Dakota Electric requests that the Commission:

1. Authorize an overall revenue increase of $4,189,232 or about 2.11 percent.
2. Approve the pro forma Test Year Revenue Requirements contained in Exhibit__(DEA-1).
3. Approve a Rate of Return on Rate Base of 6.52 percent as calculated in Exhibit__(DEA-2).
4. Grant the Cooperative's request for consideration of MDSC when approving Rate of Return in future general rate cases.

5. Approve the Cooperative’s Cost of Service study as contained in Exhibit__(DEA-3), including the use of the minimum size method in this and future general rate proceedings for the Cooperative.
6. Approve the charges for retail rate schedules as described in this testimony and contained in Exhibit__(DEA-6) and proposed tariff pages included in Exhibit__(DEA-18) and Exhibit__(DEA-19).
7. Approve the RTA base components contained in Exhibit__(DEA-12) and as reflected in proposed tariff pages shown in Exhibit__(DEA-18) and Exhibit__(DEA-19).
8. Approve the proposed Special Fees and Charges shown in Exhibit__(DEA-10).
9. Approve the proposed changes for individual residential line extensions as described in this testimony and analyzed in Exhibit__(DEA-11).
10. Approve the proposed modifications/clarifications to tariff pages in Section VI of the Cooperative’s rate book.

Q. Does this conclude your prefiled Direct Testimony?

A. Yes, it does.

Schedule 1
Professional and Educational Background
Direct Testimony of Douglas R. Larson
Docket No. E-111/GR-14-482

PROFESSIONAL EXPERIENCE

Dakota Electric Association – Farmington, Minnesota (2008 – Present)

Vice President of Regulatory Services

Responsible for regulatory matters including developing new rates, monitoring existing rates, submitting miscellaneous tariff filings, and coordinating and/or preparing all necessary information pertaining to rate increase filings; evaluating power supply issues through participation in meetings at Great River Energy; and monitoring state and federal electric utility and environmental legislation and determining the potential affect on DEA's operation as a distribution cooperative.

Power System Engineering – Blaine, Minnesota (1998 – 2008)

Vice President of Rates and Financial Planning

Senior Rate and Financial Analyst

Manager of PSE's Blaine, Minnesota office. Responsibilities include preparation of rate and cost of service analyses for electric cooperative and municipal clients; economic evaluation of mergers, acquisitions and special programs; key account analysis; development of large power contracts and special rates; development of restructuring plans and various elements of such plans; and development of financial forecast and economic feasibility studies.

Dakota Electric Association – Farmington, Minnesota (1992 – 1998)

Director of Regulatory & Legislative Affairs

Coordinated and/or prepared all necessary information pertaining to rate filings, cost of service studies, new rate proposals and miscellaneous tariff filings. Monitored state and federal electric utility and environmental legislation to determine the potential effect on Dakota Electric's operations as a distribution cooperative. Participated in statewide rulemaking proceedings initiated by state agencies that affect electric utility operations. Prepared and conducted conservation, rate and industry-related presentations for consumer and other public meetings.

Dakota Energy Alternatives, Inc. – Farmington, Minnesota (1993 – 1998)

President/CEO – Unregulated Business Activities

Vice President of Business Operations

Supervised staff of professional engineers and support staff who sold and installed standby generation for commercial and industrial customers. Established relationships/partnerships with organizations to expand the standby generation business. Worked with officers to evaluate new business ventures.

Minnesota Department of Public Service – St. Paul, Minnesota (1986 – 1992)

Rate Analyst

Filed testimony in utility rate cases regarding conservation, marketing, cost of service and rate design. Reviewed service area disputes between utilities and complaints from customers and recommended corrective actions. Presented testimony to establish compensation for municipal service territory acquisitions. Reviewed miscellaneous utility filings and prepared recommendations for Public Utilities Commission action. Also participated in Public Utilities Commission task forces to revise Minnesota Rules.

Minnesota Department of Energy & Economic Development, Energy Division
St. Paul, Minnesota (1983 – 1986)

Research Analyst

Responsible for filing testimony in utility rate cases regarding conservation planning and the calculation of cost-effective utility programs. Reviewed utility conservation programs and prepared comments for the Public Utilities Commission.

EDUCATION

University of Minnesota – Minneapolis, Minnesota
Master of Business Administration
St. Olaf College – Northfield, Minnesota
Bachelor of Arts Degree in Economics

Schedule 2
Regulatory Proceedings
Direct Testimony of Douglas R. Larson
Docket No. E-111/GR-14-482

Minnesota

Docket Number	Utility	Type of Proceeding
G009/GR-84-128	Montana-Dakota Utilities	Rate Case
G007/GR-84-669	Inter-City Gas	Rate Case
G002/GR-85-108	Northern States Power	Rate Case
G,E-999/R-86-322	Cold Weather Rules	Rulemaking
E001/GR-86-384	Interstate Power	Rate Case
E221,148/SA-87-661	City of Buffalo & Wright-Hennepin Cooperative	Service Territory
E002/GR-87-670	Northern States Power	Rate Case
E132, 299/SA-88-270	City of Rochester & Peoples Cooperative	Service Territory
E132,299/SA-88-996	City of Rochester & Peoples Cooperative	Service Territory
E002/GR-89-865	Northern States Power	Rate Case
E309,124/SA-89-778	City of Shakopee & Minnesota Valley Coop	Service Territory
G010/GR-90-678	Midwest Gas	Rate Case
E002/GR-91-001	Northern States Power	Rate Case
E002/CN-91-019	Northern States Power	Certificate of Need
E111/GR-91-074	Dakota Electric Association	Rate Case
E111/GR-03-261	Dakota Electric Association	Rate Case
E111/GR-09-175	Dakota Electric Association	Rate Case

Kansas

Docket Number	Utility	Type of Proceeding
01 PNRE 058-RTS	Pioneer Electric Cooperative	Rate Case

Iowa

Docket Number	Utility	Type of Proceeding
RPU-02-1	Linn County REC	Rate Case