MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	June 18, 2020		Agenda Item 1**
Company	Dakota Electric Association		
Docket No.	**E-111/GR-19-478**		
	In the Matter of the Application by Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota		
Issues	Should the Commission adopt the recommendations in the ALJ's Report?		
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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

✓ **Relevant Documents**	**Date**
Dakota Electric Association - Settlement Correspondence	January 31, 2020
Court Reporter – Master Exhibit List	February 7, 2020
Dakota Electric Association – Proposed Findings	February 28, 2020
Minnesota Department of Commerce, Division of Energy Resources - Letter	March 3, 2020
Minnesota Office of Attorney General – Residential Utilities Division – Letter (Revised)	March 3, 2020
ALJ Report	
Findings of Fact, Conclusions of Law and Recommendation	April 17, 2020
Dakota Electric Association - Schedules Reflecting ALJ Recommendation	April 24, 2020
Minnesota Department of Commerce, Division of Energy Resources-Comments on DEA's Schedules	May 4, 2020
Exceptions to the ALJ Report	
Minnesota Office of Attorney General – Residential Utilities Division	April 28, 2020
Minnesota Department of Commerce, Division of Energy Resources	May 4, 2020
Dakota Electric Association	May 4, 2020

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I. Statement of the Issues

Should the Commission adopt the recommendations in the ALJ's Report?

II. Introduction

Dakota Electric Association (Dakota Electric, DEA, or the Company) is an electric distribution-only utility that serves approximately 108,000 customers (members) in Dakota County and portions of Scott, Rice, and Goodhue Counties in Minnesota. The Company has projected total annual electricity sales of 1,824,313,200 kWh. It does not generate electricity nor own any high voltage transmission lines. Instead, it purchases its wholesale power and related transmission services from Great River Energy (GRE) of Maple Grove, Minnesota.[1]

On April 17, 2020, the Administrative Law (ALJ) James E. LaFave issued his Findings of Fact, Conclusions and Recommendation (ALJ Report). If the Commission approves the ALJ Report, Dakota Electric's requested $8.7 million rate increase, or approximately 4.3 percent, would be reduced to approximately $8.5 million, or 4.25 percent.

The main issue before the Commission is whether to adopt the ALJ's Report (and recommendation).

If the Commission does not accept the ALJ's Report (and recommendations) in its entirety, then, based on Commission modifications, it will need to decide the Company's appropriate test year revenue level and how that revenue should be collected from customers.

III. Background

On September 19, 2019, Dakota Electric filed a general rate case with the Minnesota Public Utilities Commission (Commission) (Docket No. E-111/GR-19-478). The Company requested an increase of $8.7 million, or 4.3 percent, in its Minnesota retail electric rates, effective November 18, 2019. The 2020 revenue requirement is based on a historical 2018 test-year, adjusted for known and measurable changes, and a proposed rate of return on total equity capitalization of 5.73 percent.

On November 7, 2019, the Commission issued three Orders.[2] In those Orders, the Commission accepted DEA's filing, suspended the proposed final rates until the end of this case, and set this matter for contested case hearing. The Commission also authorized an interim rate increase of approximately $6 million per year, or approximately 3 percent, effective November 18, 2019 and subject to refund.

Administrative Law Judge (ALJ) James E. LaFave of the Minnesota Office of Administrative Hearings (OAH) was assigned to conduct the case.

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1 ALJ Report Finding of Fact No. 2.

2 ORDER ACCEPTING FILING AND SUSPENDING RATES; NOTICE AND ORDER FOR HEARING; and ORDER SETTING INTERIM RATES (this docket).

The parties in this case are:

- Dakota Electric Association
- Minnesota Department of Commerce-Division of Energy Resources (the Department)
- Minnesota Office of the Attorney General-Residential Utilities Division (OAG)

Dakota Electric, the Department, and the OAG submitted prefiled testimony in advance of the evidentiary hearings. (Copies of the prefiled testimony are available electronically through the eDockets system.)

On January 13, 2020, Judge LaFave held two public hearings, with attendance as follows:

Table 1: Summary of Public Hearings

Location, date & time	Members of the public in attendance	Members of the public who spoke
Apple Valley Senior Center Apple Valley – January 13, 2020 (2:00 p.m.)	24	13
Farmington Public Library – January 13, 2020 (6:00 p.m.)	2	2

Additionally, twenty-one written public comments were received by the ALJ and the Commission combined. Fifteen commenters expressed general opposition to the rate increase request, with some of those commenters focusing on the impact to members living on fixed incomes. Two commenters stated that Dakota Electric would not need to raise rates if it were not investing in wind and solar energy. One commenter raised a concern about the timeliness of a recent member dividend payment he received. One commenter expressed frustration that his trees had not been trimmed for some time and may not be trimmed for another one to two years. One commenter objected to the proposed increase in the monthly customer charge. One commenter expressed support for the request.[3] Copies of the public hearing transcripts and the written public comments are available electronically.

On January 31, 2020, Dakota Electric filed a letter informing the ALJ that all disputed issues had been resolved.

On February 5, 2020, the ALJ convened the hearing in the Commission's Large Hearing Room, for the limited purpose of receiving into evidence all parties' exhibits and establishing the schedule for post-hearing filings. A copy of the evidentiary hearing transcript is also available electronically.

On April 17, 2020, ALJ LaFave issued his Findings of Fact, Conclusions of Law and Recommendations (ALJ Report).

3 ALJ Report Finding of Fact No. 37.

On April 24, 2020, Dakota Electric submitted financial schedules that reflect its interpretation of the test-year revenue requirement and rate design recommended by the ALJ.

On April 28, 2020, the OAG filed exceptions to the ALJ Report.

On May 4, 2020, the Department submitted a letter confirming its agreement with Dakota Electric's schedules.

On May 4, 2020, the Department and Dakota Electric filed their exceptions to the ALJ Report.

Issues Set for Hearing

In its November 7, 2019 Notice and Order for Hearing, the Commission identified the following issues for parties to address in this proceeding:

1. Whether the test year revenue increase sought by Dakota Electric is reasonable or will result in unreasonable or excessive earnings;
2. Whether Dakota Electric's proposed capital structure and return-on-equity are reasonable;
3. Whether the rate design proposed by Dakota Electric is reasonable;
4. The cause(s) for the 32.31% increase in Customer Accounts expenses since 2014; and
5. The cause(s) for the 26.85% increase in Administrative & General expenses since 2014.

Staff believes each of these items has been adequately addressed in this proceeding.

IV. Exceptions to ALJ Report

A. The Department

The Department filed limited exceptions to the ALJ Report clarifying the procedural record. Specifically, the Department proposed the following corrections and additions:

> Dakota Electric filed its proposed Findings of Fact, Conclusions of Law and Recommendation on February 28, 2020. The Department and OAG filed ~~replies~~ letters on March 5th and 3rd ~~12~~, 2020, respectively. The Department's letter stated that it agreed with Dakota Electric's proposed findings. OAG's letter stated that it supported Dakota Electric's proposed findings in sections V.H, V.I, and VII and took no position on the remainder of Dakota Electric's submission.

The Department also recommended two minor corrections to citations to the Department's testimony in footnotes 30 and 131 of the ALJ's report. The corrections are provided below:

• 30 Ex. DOC-~~8~~9 at 7 (Johnson Surrebuttal).
• 131 See Ex. DOC-8 at 13 (Johnson ~~Surrebuttal~~ Direct).

With these minor corrections and clarifications, the Department recommended that the Commission adopt the ALJ's Report in setting final rates in this matter.

1. PUC Staff Comments

Staff reviewed the Department's recommended footnote corrections and it appears that the Department intended the corrections to be made to footnotes 130 and 131 of the ALJ Report. Footnote 30 of the ALJ Report pertains to the Apple Valley public hearing transcript. Outside of that minor correction, staff has no additional comment on the Department's exceptions.

B. OAG

The OAG took no exception with respect to the ALJ's Report. However, the OAG made the following recommendation:

> The OAG recommends that the Commission adopt Findings 61-63 and 80-83, and takes no position with respect to the remainder of the Report. By way of clarification, the OAG notes that, when describing the treatment of Account 37020 (meters – used), Finding 82 refers to a "true-up calculation that will be made at the end of 2020 and then will include it as part of the annual AGi Rider filings in the future, until the Cooperative's next rate case filing." The OAG understands "in the future," as used in this Finding, to mean that this calculation will be made prospectively at the beginning of 2021 and every subsequent year, until the Cooperative's next rate case filing. [Footnote omitted]

C. Dakota Electric

Dakota Electric did not file exceptions to the ALJ Report but noted the following regarding the Department's exceptions:

> Dakota Electric Association has also fully reviewed the Administrative Law Judge's Findings of Fact, Conclusions of Law and Recommendations ("Report") in this matter and takes no exception to Administrative Law Judge LaFave's Report. The Report reflects the record and the agreements reached by the parties during the course of this proceeding and agrees with the OAG comments regarding the AGi Rider and the Department's minor corrections and clarifications. Therefore, Dakota Electric Association respectfully requests that the Commission adopt the Report, with any minor clarifications deemed necessary.

V. Financial Issues

A. Organization and Membership Dues and Lobbying Expenses

PUC Staff: Godwin Ubani

1. Introduction

This issue was originally disputed between Dakota Electric and the Department.

2. Reference to Record

DOC Ex. 8 at 8-12, MAJ-9 (Johnson Direct)
DEA Ex. 53 at 4-6, Sch. DEA-1 (Larson Rebuttal)
DOC Ex. 9 at 3-7, Sch. MAJ-S-8 (Johnson Surrebuttal)
Court Reporter, Ex. DEA-55 (Letter from Eric F. Swanson to The Honorable James E. LaFave, Jan. 31, 2020).
ALJ Report Findings of Fact 55-58

3. Parties Positions

Dakota Electric, in its initial filing, included for recovery dues of $276, 823, of which $80,579 was for National Rural Electric Cooperative Association (NRECA) membership, and $152,010 was for Minnesota Rural Electric Association (MREA) membership.

In Direct, the Department argued against allowing Dakota Electric recovery of the full organization dues and membership amounts paid to NRECA and MREA. The Department maintained this contravenes the Commission's Statement of Policy on Organization Dues made on June 14, 1982. Part of the Policy states:

> The Commission does not feel it can impose on customers the expense of dues when it has not been shown that customers receive any benefit for the organizations receiving the dues, as may be the case when the organizations are lobbying or social in purpose, or where there is no connection between the expense and reasonable and reliable utility service.

Further, in Direct, the Department stated that Dakota Electric's response to the OAG's information request indicated that NRECA's billing statement stated that, in accordance with Internal Revenue Code (IRC) Section 162(2)(3) and 6033(e)(1) as amended, it allocated 13% of 2018 dues to lobbying expenses. Therefore, Dakota Electric cannot deduct this 13% portion of its federal income tax return. The Department maintained that, consistent with Commission's 1982 Statement of Policy on Organization Dues, ratepayers should not have to pay for any portion of NRECA dues that are considered as lobbying expenses.

Also, in Direct the Department stated that Dakota Electric indicated that government affairs is one of the three functions for use of dues paid to MREA. Since government affairs includes lobbying, the Department concluded that a third of the $152,010, or $50,670, MREA dues was used for lobbying.

Further, in Direct, both the Department and OAG proposed a reduction of $61,145 ($10,475 and $50,670) related to dues to NRECA and MREA, as this amount represent lobbying expenses

In Rebuttal, Dakota Electric agreed to exclude the $10,475 from membership dues paid to NRECA as recommended by the Department. Dakota Electric disagreed with the $50,670 adjustment recommendation related to MREA dues. Dakota Electric argued that the 15.44% of its membership dues to MREA is attributed to lobbying; therefore, the adjustment should be $23,470 and not $50,670.

In Surrebuttal, the Department disagreed with Dakota Electric's rebuttal calculations of approximately 15.44% of MREA's expenses and instead suggested that 16.03% of the expenses are attributable to lobbying activities which resulted in a $24,367 adjustment.

4. Resolution

Parties agreed to remove $10,457 and $24,367 as recommended by the Department.

5. ALJ Report

The ALJ Report recommended that the Commission accept the resolution reached by the parties.

6. PUC Staff Comment

Staff observes that the Department agrees with Dakota Electric that lobbying expenses do not constitute a third of the Company's membership dues paid to MREA in relation to MREA's three main functions. However, both parties disagree on the percentage of the membership dues amount of $152,010 to exclude. Dakota Electric opts for 15.44% and the Department opts for 16.03%, that is in dollars $23,470 versus $24,367, a difference of $897. However, by correspondence to the ALJ dated January 31, 2020, Dakota Electric agreed to the higher adjustment. Thus, in view of the small amount in dispute, Staff believes the settlement to be reasonable.

7. Decision Alternatives

101. Disallow Dakota Electric recovery of $10,475 of NRECA organization and membership dues. (Department Direct, Parties Agreed, ALJ)

102. Disallow Dakota Electric recovery of $24,367 of MREA organization and membership of dues. (Department in Surrebuttal, Parties Agreed, ALJ)

103. Allow Dakota Electric to recover $80,575 of NRECA organization and membership dues. (Dakota Electric Initial Filing)

104. Allow Dakota Electric to recover $152,010 of MREA organization and membership dues. (Dakota Electric Initial Filing)

B. Travel Expenses

PUC Staff: Godwin Ubani

1. Introduction

The issue was originally disputed between Dakota Electric and the OAG.

2. Reference to Record

OAG Ex. 1 at 2-3, and 8, Sch. 1 (Lee Direct)
DEA Ex. 53 at 14-15 (Larson Rebuttal)
OAG Ex. 2 at 1 (Lee Surrebuttal)
Court Reporter, Ex. DEA-55 (Letter from Eric F. Swanson to The Honorable James E. LaFave, Jan. 31, 2020).
ALJ Report Findings of Fact 62-63

3. Parties Positions

Dakota Electric, in its initial filing, requested cost recovery of $182,546.94 as travel expenses for the Test Year. This amount comprises $92,941.35 for travel expenses and $89,605.59 for meal related expenses.

In Direct, OAG objected to the amount of travel expenses that Dakota Electric included in the test year because it included $3,548.86 for travel expenses related to Touchstone Energy Meetings. OAG noted that "The Cooperative has stated that Touchstone primarily does branding work for them". The amount was improperly coded to a project labelled as "ACS". Thus, OAG holds that, under Minnesota Statutes section 216B.16, subdivision 17, any travel expense associated with an organization providing branding services is unnecessary for the provision of utility service. The OAG recommended that recovery of the $3,548.86 be disallowed.

In Rebuttal, Dakota Electric disagreed with OAG and held that it only included travel expenses associated with Touchstone Energy Board meetings and; therefore, are not branding expenses. Dakota Electric asked the Commission to allow recovery of the $3,548.86.

In Surrebuttal, the OAG stated that Dakota Electric agreed to remove the $3,548.86 from the Test Year and considered its concerns about Touchstone travel expenses resolved.

4. Resolution

Parties agreed to accept the OAG's recommendation.

5. ALJ Report

The ALJ notes in his report that Dakota Electric provided testimony objecting to this recommended adjustment, but had subsequently filed correspondence with the Administrative Law Judge stating that it no longer contests the adjustment.

The ALJ recommends the Commission accept the parties' resolution.

6. PUC Staff Comment

The Parties' resolution appears reasonable.

7. Decision Alternatives

105. Disallow recovery of $3,548.86 in travel expenses. (OAG Direct, Parties agreed, ALJ)

106. Allow Dakota Electric to recover all travel expenses related to Touchstone Energy Meetings. (Dakota Electric Initial Filing)

C. Community Events

PUC Staff: Godwin Ubani

1. Introduction

The issue was originally disputed between Dakota Electric and the OAG.

2. Reference to Record

OAG Ex. 1 at 3-5 (Lee Direct)
DEA Ex. 53 at 16-17 (Larson Rebuttal)
OAG Ex. 2 at 2 (Lee Surrebuttal)
Court Reporter, Ex. DEA-55 (Letter from Eric F. Swanson to The Honorable James E. LaFave, Jan. 31, 2020).
ALJ Report Finding of Fact 61

3. Parties' Positions

Dakota Electric included in the rate case test year Community Events expenses totaling $15,929.10, for payments to various groups like Rotary clubs, area chamber of commerce, cities, curling tournaments, award dinners, golf tournaments, galas, breakfast, and holiday parties, etc.

In Direct, OAG stated "Many of the payments listed under "Community Events" were made to the same organizations and groups that have received donations from the Cooperative". Dakota Electric claimed that these expenses were incurred by employees for their events and, for this fact, are classified as "employee expenses" and cannot be compared to direct Cooperative donations. OAG stated that in prior rate cases recovery of half of utilities charitable contributions have been allowed by the Commission. Thus, OAG recommends that DEA should adjust the $15,929.10 "Community events" expenses by fifty percent (50%) and remove $7,964.55 from the Test Year.

In Rebuttal, Dakota Electric disagreed with OAG's recommendation. Dakota Electric held that these community events expenses are not donations as implied by OAG, but expenses that allow Board of Directors, Management and staff to be connected to the Cooperatives' members.

In Surrebuttal, OAG stated that Dakota Electric agreed to remove one half of the costs at issue by making a $7,964.55 adjustment (reduction) to the test year expenses. OAG stated that this reduction resolves its concerns with the classification of employee travel expenses for Community Events.

4. Resolution

Parties agreed to accept OAG's recommendation.

5. ALJ Report

The ALJ report stated that Dakota Electric provided testimony objecting to this recommended adjustment; however, DEA subsequently filed correspondence with the Administrative Law Judge stating that it no longer contests the adjustment recommended by OAG.

The ALJ recommended the Commission accept the parties' agreement.

6. PUC Staff Comment

The Parties' resolution appears reasonable.

7. Decision Alternatives

107. Disallow recovery of $7,964.55 in Community Events expenses. (OAG Direct, Parties agreed, ALJ)

108. Allow Dakota Electric to recover $15,929.10 in Community Events expenses. (DEA Initial Filing)

D. Property Tax Rates

PUC Staff: Jorge Alonso

1. Introduction

The issue was originally addressed by the Department.

2. Reference to Record

DEA Ex. 39 at 2 (Workpaper 14)
DOC Ex. 1 at 3-4, GKM-1 (Miltich Direct)
DEA Ex. 53 at 3-4 (Larson Rebuttal)
ALJ Report Finding of Fact 53

3. Parties' Positions

In Direct, the Department stated that, in its review of Dakota Electric's property tax rates, it discovered large discrepancies between the property tax amounts calculated the Department and the Company. In response to the Department's IRs 112 and 113, DEA explained that the discrepancies were due to a formula error in its tax rate calculation; however, the formula error did not impact tax amount included in the revenue requirement. Based on Dakota Electric's response, the Department concluded that no adjustment was necessary.

In Rebuttal, Dakota Electric agreed with the Department's conclusion.

4. Resolution

Parties agreed to accept the Department's recommendation.

5. ALJ Report

The ALJ did not explicitly express a position on this issue. However, since the ALJ report recommended approval, the ALJ implicitly recommends that the Department's finding be adopted.

6. PUC Staff Comment

Since the formula error did not impact financial calculations, staff agrees that no action is required on this matter.

E. Non-Operating Income

PUC Staff: Jorge Alonso

1. Introduction

The issue was originally addressed by the Department.

2. Reference to Record

DOC Ex. 8 at 5-8, MAJ-8 (Johnson Direct)
DEA Ex. 53 at 4-5 (Larson Rebuttal), pp. 4-5
ALJ Report Finding of Fact 54

3. Parties' Positions

In Direct, the Department noted that, in its initial filing, Dakota Electric included $8,227 in net income for its wholly-owned for-profit subsidiary, thus reducing the revenue requirement. Utility rates are normally calculated on a stand-alone basis and do not include income (or losses) from an unregulated subsidiary in the determination of just and reasonable rates and, while in this case, inclusion of the subsidiary income would have reduced the Cooperative's revenue requirement, the Department pointed out that, in past years, the subsidiary suffered substantial losses which were not included in rates. Such an inclusion would have increased

DEA's revenue requirement in the past. Therefore, the Department recommended removing the $8,227.

In Rebuttal, Dakota Electric accepted the Department's recommendation.

4. Resolution

Parties agreed to accept the Department's recommendation.

5. ALJ Report

The ALJ did not explicitly express a position on this issue. However, since the ALJ report recommended approval, the ALJ implicitly recommends that the Department's finding be recommendation.

6. PUC Staff Comment

Staff agrees with the Department's recommendation to remove the subsidiary's $8,227 profit from the revenue requirement calculation.

7. Decision Alternatives

109. Order that the $8,227 in wholesale margin net income be removed from the revenue requirement calculation. (Department Direct, Parties agreed, ALJ)

110. Order that the $8,227 in wholesale margin net income be included in the revenue requirement calculation. (Dakota Electric Initial Filing)

F. Sales Revenue and Purchased Power Expense

This issue is discussed in the sales forecast section of these briefing papers.

G. Cash Working Capital

PUC Staff: Jorge Alonso

1. Introduction

The issue was originally addressed by the Department.

2. Reference to Record

DOC Ex. 8 at 12-13, MAJ-5 (Johnson Direct)
DEA Ex. 53 at 5 (Larson Rebuttal)
DOC Ex. 9 at 7-8, MAJ-S-5 (Johnson Surrebuttal)
ALJ Report Finding of Fact 61
Dakota Electric Compliance Filing: Rate of Return Adjustment Reconciliation

3. Parties' Positions

To account for the impact of its recommendations on the lead/lad study, in Direct, the Department recommended a $5,276 reduction in cash working capital. The Department noted that this reduction does not account for adjustments recommended by the OAG. Adoption of any recommendations not proposed by the Department will require a recalculation of the cash working capital adjustment.

In Rebuttal, Dakota Electric accepted the Department's recommendation.

Based on changes to its recommendations, in Surrebuttal, the Department revised its cash working capital calculation to a $2,622 reduction.

4. Resolution

Parties agreed to accept the Department's recommendation.

5. ALJ Report

The ALJ did not explicitly express a position on this issue. However, since the ALJ report recommended approval, the ALJ implicitly supports that the Department's $2,622 reduction recommendation.

6. Dakota Electric Compliance Filing

To account for the cash working capital impact of the OAG's recommendations, in its April 24, 2020 compliance filing, Dakota Electric further reduced cash working capital by $1,162.

7. PUC Staff Comments

Staff reviewed the final cash working capital adjustment calculation and agrees with it.

8. Decision Alternatives

111. Approve the methodology used to calculate the cash working capital included in rate base. (Department Direct, Parties agreed, ALJ)

H. Meter Plant Balance

PUC Staff: Jorge Alonso

1. Introduction

The issue was originally disputed between Dakota Electric and the OAG.

2. Reference to Record

OAG Ex. 1 at 5-7 (Lee Direct)
DEA Ex. 3 (Interim Exhibits)
DEA Ex. 53 at 18-21 (Larson Rebuttal)
OAG Ex. 2 at 2-4(Lee Surrebuttal)
ALJ Report Findings of Fact 80-83
Court Reporter, Ex. DEA-55 (Letter from Eric F. Swanson to The Honorable James E. LaFave, Jan. 31, 2020)

3. Parties' Positions

In direct, the OAG stated that Dakota has included the current cost of meters in the test year revenue requirement. Since these meters, under the Company's Advanced Grid Infrastructure (AGI) plan, will be replaced by new smart meters, the OAG expressed concerns regarding the duplicative meter costs that will be recovered through base rates and the AGI rider until Dakota Electric's next rate case. In fact, Dakota Electric anticipates completing all meter replacements by 2023 and does not anticipate filing a new rate case until 2024, thus ratepayers will be paying for both meters until the next rate case. Additionally, under the Company's current depreciation schedule, the current meters will be fully depreciated at the end of 2021.

However, if a new rate case is not filed until 2024, ratepayers will continue paying for assets that they have paid for in full and have possibly been replaced by the new smart meters thus making current meters no longer used and useful. The OAG recommended the Commission order a sunset provision for the undepreciated plant balance of current meters and, effective in 2022, order Dakota Electric to take those meters' annual revenue requirement out of base rates. Also effective in 2022, the OAG recommended that Dakota Electric update its base rates to reflect the lower plant balance for current meters in account 37000 – Meters, such that ratepayers receive the benefit of paying for the rate of return on the lower undepreciated plant balance for current meters. As an alternative to updating base rates in 2022, the OAG recommended that the adjustments be made in the AGI rider.

In Rebuttal, Dakota Electric agreed in concept with the OAG concerns and proposed to address these concerns through adjustments to the AGI Rider. In the AGI Rider, the DEA committed to making the following adjustments:

- For Account 37020 (Meters – Used): Dakota Electric agreed to make an adjustment (credit) in the AGI Rider related to Acct 37020. DEA explained that the test year includes $17,771 of annual depreciation expense associated with this account. As of December 31, 2018, the end of the test year, the net book value of the account was $12,369 and the account will be fully depreciated by the end of 2019. Dakota's adjustment (credit) will consist of two components: depreciation and rate of return. The depreciation component equals the $17,771 of annual expense and the rate of return component would equal the Cooperative's applicable approved Rate of Return times the net book value (rate base) amount of $12,369 for this account, or $703.00. Since the AGI Rider amounts have already been filed and implemented for 2020, Dakota Electric will apply this credit to the true-up calculation that will be made at the end of 2020 and then will include it as part of the annual AGI Rider filings in the future, until DEA's next rate case filing.

• For Account 37000 (Meters): Starting in 2022, Dakota Electric agreed to make an adjustment (credit) in the calculation of the AGI Rider. In the test year, there was $465,604 of annual depreciation associated with this account. As of December 31, 2020, the end of the test year, the net book value of this account was estimated to be $2,622,285, and Dakota Electric will continue to incur depreciation expense for meters in Acct 37000 until near the end of 2024. Dakota Electric agreed to make an adjustment (credit) in the calculation of the 2022 AGI Rider (and each year thereafter until its next rate filing) for Account 37000 that reflects the reduction in net book value from the end of the test year to December 31, 2021 times the approved rate of return, or approximately $74,000.

In Surrebuttal, the OAG stated that Dakota Electric's proposed adjustments resolve the concerns related to the meter plant balance issue.

4. Resolution

Parties agreed to accept the OAG's recommendation.

5. ALJ Report

The ALJ did not explicitly express a position on this issue. However, since the ALJ report recommended approval, the ALJ implicitly supported the Company's proposal to account for the adjustments in the AGI Rider.

6. PUC Staff Comment

Staff believes Dakota Electric's proposal to make their proposed adjustments in the AGI Rider to be reasonable.

7. Decision Alternatives

112. Allow adjustments credits related to Meter Plant Balance to flow through the AGI Rider. (DEA Rebuttal, Parties agreed, ALJ)

113. Do not allow adjustments credits related to Meter Plant Balance to flow through the AGI Rider.

I. Customer Accounts Expense

PUC Staff: Jorge Alonso

1. Introduction

The issue was included in the Commission's November 7, 2019 Order referring this matter to the Office of Administrative Hearings. The Order requested that a record addressing the cause(s) for the 32.31% increase in Customer Accounts expenses since 2014 be developed.

2. Reference to Record

PUC Notice of and Order for Hearing: p. 2
DOC Ex. 8 at 18-19, MAJ-11 and MAJ-13 (Johnson Direct),
ALJ Report Finding of Fact 65

3. Parties' Positions

Based on its analysis, the Department noted that the proposed increase is largely accounted for by three items:

- increases in labor and benefits which accounted for over half of the increase,
- implementation of a new customer information system that replaced a 20-year old legacy system, and
- billing costs, due to process changes related to the new customer information system.

Based on its analysis, the Department concluded that Dakota's proposed test year increase in Customer Accounts expense is consistent with past practice and appears reasonable.

4. ALJ Report

The ALJ did not explicitly express a position on this issue. However, since the ALJ report recommended approval, the ALJ implicitly accepted the Department analysis.

5. PUC Staff Comment

Staff reviewed the Department's analysis and agrees with the DOC's conclusion that the changes are reasonable. Staff does not believe any affirmative Commission action is needed to accept or agree with the Department's conclusion.

J. Administrative and General Expenses

PUC Staff: Jorge Alonso

1. Introduction

The issue was included in the Commission's November 7, 2019 Order referring this matter to the Office of Administrative Hearings. The Order requested that a record addressing the cause(s) for the 26.85% increase in Administrative & General expenses since 2014 be developed.

2. Reference to Record

PUC Notice of and Order for Hearing: p. 2
DOC Ex. 8 at 15-17, MAJ-12 and MAJ-14 (Johnson Direct)
ALJ Report Finding of Fact 66

3. Parties' Positions

Based on its analysis, the Department noted over two-thirds of the proposed increase was related to labor and benefits increases, the addition of a Vice President for Information Services not included in the Cooperative's last rate case, and transfer of Information Technology staff previously accounted for in Distribution Operations expense. Based on its analysis, the Department concluded that Dakota's proposed test year increase in Customer Accounts expense is consistent with past practice and appears reasonable.

4. ALJ Report

The ALJ did not express a position on this issue. However, since the ALJ report recommended that the settlement be approved, the ALJ implicitly accepted the Department analysis.

5. PUC Staff Comment

Staff reviewed the Department's analysis and agrees with the Department's conclusion that the changes are reasonable. Staff does not believe any affirmative Commission action is needed to accept or agree with the Department's conclusion.

VI. Class Cost of Service Study

PUC Staff: Robert Manning

A. Introduction

Dakota Electric filed its proposed Class Cost of Service Study to provide information to be used in designing rates. The purpose of a Class Cost of Service Study (CCOSS) is to allocate costs, which have been previously categorized based on the Uniform System of Accounts, to the various functions of a utility (e.g. Generation, Transmission, Distribution, General/Customer Service) and to the rate classes, based on which class or classes, and function or functions, 'caused' the costs in each account to be incurred.[4] The CCOSS is then used in the rate design process to aid in determining the appropriate billing determinant to use to recover the costs delegated to each customer class. Dakota Electric provided a detailed Guide to its CCOSS as Attachment 22 to its rate case, which provides detail on how it functionalized and allocated the costs for each account in the Uniform System of Accounts. Dakota Electric used what is known as a "fully allocated average embedded cost of service" approach, which is typical for this jurisdiction. This means that costs are allocated on an average system-wide basis (rather than calculating the marginal cost of service) and the 'embedded' (accounting) costs, as recorded on Dakota Electric's books, are used for the model.

The first step of a CCOSS is functionalization, which assigns all costs to a specific utility function, such as generation, transmission, etc. The Federal Energy Regulatory Commission (FERC) has created a Uniform System of Accounts (or FERC Accounts) which most utilities use in their accounting systems to record and classify costs. Dakota Electric functionalized its costs to Purchased Power, Transmission, and Distribution functions.

Once the costs are functionalized, the costs in each account are classified as customer, demand, or energy costs. This classification is used to generally inform whether the cost is recovered through a customer charge, an energy (per kWh) charge, or a demand (per peak demand kw usage) charge.

Customer costs are those that scale with the number of customers. Typical customer related costs include billing costs, 'minimum system' costs which consist of the minimum amount of equipment (for example, meters, which every non-lighting customer has at point of delivery) required to hook up a customer to the grid, and customer service.

Energy costs are those that scale with electricity total usage, for example, purchased energy or fuel for generation. Demand costs are those that scale with maximum usage, such as purchased demand, transmission capacity, distribution capacity.

Finally, the costs are allocated to customer class. Each FERC Account is allocated across the various customer class by an allocation factor. Typically, as many costs as possible are allocated 'directly', meaning they are assigned to the customer classes they serve. For example, costs related to a substation which only serves large industrial customers might be directly allocated

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4 A guide to Dakota Electric Association's Class Cost of Service Study was provided as DEA Ex. 48 (Workpaper 22).

to the large industrial class. Once costs which can be directly allocated are, those that are left are allocated based on allocation factors which are determined based on how those costs were classified and functionalized. For example, transmission assets are usually classified as demand related, and would be allocated in proportion to each customer class' power usage at the peak demand time(s) for the utility.

Dakota Electric used the same model that was approved in its last rate case, with one modification. In Docket GR-14-482, the Commission required that Dakota Electric include a demand adjustment to its minimum system allocator in its CCOSS submitted in its next (i.e. this) rate case.[5] A minimum system allocator attempts to identify the lowest cost system which would be installed if demand (load) were not an issue. For example, Account 364 consists of Poles, Towers, and Fixtures, and is the accumulated cost of all utility poles and towers installed on the system. The minimum system allocator calculates how much the system would have cost to build if the lowest cost poles (for example) in widespread use had been used to construct the entire system. This minimum cost is then attributed to customers, and costs are allocated to the "customer service" function which is usually allocated on a per customer basis to class, and would be theoretically billed via the customer charge.

In this case, Dakota Electric developed four scenarios to evaluate minimum system:

1. 1 kW Feeder with load growth percentages applied
2. 100 kW and 500 kW per feeder options
3. 200 kW per feeder
4. 200 kW per feeder and then increasing load on individual substations.

Dakota Electric found that each of the first three scenarios caused significant reliability errors, and so adopted scenario 4. The results of this classification are below:

Table 2 – Consumer Component of Distribution System Accounts by Method[6]

Account	Minimum System	**Demand Adjusted**
364 – Poles, Towers and Fixtures	44%	**44%**
365 – Overhead Conductors and Devices	28.76%	**16.52%**
367 – Underground Conductors and Devices	78.63%	**74.96%**
Account 368 – Line Transformers	30.6%	**18.67%**

The demand adjustment notes that this minimum system size still is capable of serving a minimum load greater than zero, and so some of the cost allocated to the consumer component is still demand-related. The adjustment then removes from the consumer component the average installed cost per system peak load demand unit (kilowatts) times this minimum load, and reassigns it to demand. The effect is to allocate less of these accounts on a customer basis, and more on a demand or energy basis.

5 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, Findings of Fact, Conclusions, and Order at 27 (June 8, 2015).
6 DEA Ex. 47 at 12 (Workpaper 21).

This adjustment to the minimum system allocator makes it more similar to a 'zero intercept' allocator, which uses linear regression to predict the cost of the poles (in this example) using their capacity-related attributes as independent variables, and attributes to customer counts the constant term in the regression (which is the zero intercept, the cost of a theoretical pole where capacity is equal to zero). For comparison and further information, DEA also provided a summary comparison to a zero-intercept model in its workpapers.[7]

The results of the Class Cost of Service Study are summarized below:

Table 3: Results of Class Cost of Service Study by Category[8]

Rate Class	Cost Category			Total Cost $
	Power Supply $	Transmission $	Distribution $	
Residential & Farm	65,457,456	13,696,762	40,321,277	119,475,495
Small General Service	3,298,400	706,106	2,237,776	6,242,283
Irrigation	447,438	12,511	432,558	892,507
General Service	36,036,904	7,229,676	7,279,873	50,536,453
Interruptible Service	21,738,992	880,227	4,836,017	27,455,236
Street & Security Lighting	667,425	124,341	1,676,703	2,468,469
Total	127,646,615	22,49,623	56,774,205	207,070,443

Table 4 – Cost of Service Summary[9]

Rate Class	Revenue Present Rates	Total Cost	Increase (Decrease)	Revenue Increase Percentage
	$	$	$	%
Residential & Farm	113,507,080	119,475,495	5,968,415	5.29
Small General Service	5,732,872	6,242,283	509,411	8.94
Irrigation	917,323	892,507	(24,816)	(2.72)
General Service	50,669,263	50,536,453	(132,811)	(0.26)
Interruptible Service	25,436,728	27,455,236	(2,018,508)	7.98
Street & Security Lighting	2,079,781	2,468,469	388,689	18.79
Total	198,343,047	207,070,443	8,727,396	4.40% (4.35% Total System)

B. Reference to Record

ALJ Report Findings of Fact 71-73

7 DEA Ex. 47 at 11 (Workpaper 21).
8 DEA Ex. 6 at 31 (Larson Direct).
9 *Id,* at Table 7.

DEA Ex. 6 at 20-31 (Larson Direct)
DEA Ex. 47 (Workpaper 21 Minimum System Method)
DEA Ex. 48 (Workpaper 22 Guide to CCOS Study)
DOC Ex. 4 at 23-29 (Heinen Direct)
DEA Ex. 53 at 7-10 (Larson Rebuttal)
DOC Ex. 5 at 4-6 (Heinen Surrebuttal)

C. Parties' Positions

The Department generally agreed with the methodologies used by Dakota Electric in its CCOSS, and specifically agreed that the Demand Adjusted Minimum System study conformed to the Commission order. The Department did identify computational errors in Dakota Electric's CCOSS.

Dakota Electric reversed its consumer allocator and its capacity allocator for distribution accounts when applying the results of the minimum system model above. That is, Dakota Electric allocated consumer related costs to customer classes using the capacity (Demand) allocator, and allocated demand-related costs to customer classes using the consumer (Customer count) allocator.

Table 5: Distribution Cost Category Comparison – Dakota Electric vs Department[10]

Rate Class	DEA Distribution Cost	Department Distribution Cost
Residential & Farm	$40,321,277	$40,285,075
Small General Service	$2,237,776	$2,219,199
Irrigation	$432,558	$452,543
General Service	$7,269,873	$7,305,886
C&I Interruptible	$4,836,017	$4,838,074
Lighting	$1,676,703	$1,673,428

Correcting this error slightly adjusts the revenue requirements relative to current revenues as shown below:

Table 6: Revenue Requirement Increase/(Decrease) Comparison[11]

Rate Class	Dakota Electric Revenue Requirement	Department Revenue Requirement
Residential & Farm	5.29%	5.26%
Small General Service	8.94%	8.61%
Irrigation	(2.72%)	(0.53%)
General Service	(0.26%)	(0.19%)
C&I Interruptible	7.98%	7.99%
Lighting	18.79%	18.63%

10 DOC Ex. 4 at 27 (Heinen Direct).
11 DOC Ex. 4 at 27 (Heinen Direct).

Other than these minor adjustments, the Department found that the Dakota Electric CCOSS was generally reasonable and recommended adoption of the Company's CCOSS. The Department also recommended that Dakota Electric review its other calculations to identify any additional errors in application of its allocators that might exist. No other parties commented on the Class Cost of Service Study.

In Larson's Rebuttal Testimony, Dakota Electric concurred with the Department recommendations regarding corrections to the CCOSS, and identified one additional error in its original model. Specifically, the net plant used in its proposed CCOSS was in error in two locations, which affected the allocation of costs. The corrected cost allocation is listed below.

Table 7: Distribution Cost Comparison by Rate Class, DEA Rebuttal[12]

Rate Class	Dakota Electric Distribution Cost	Department Distribution Cost	Dakota Electric Rebuttal Distribution Cost
Residential & Farm	$40,321,277	$40,285,075	$40,285,464
Small General Service	$2,237,776	$2,219,199	$2,219,221
Irrigation	$432,558	$452,543	$452,519
General Service	$7,269,873	$7,305,886	$7,305,822
C&I Interruptible	$4,836,017	$4,838,074	$4,838,053
Lighting	$1,676,703	$1,673,428	$1,673,126

The effect of this adjustment on the Department Revenue Requirement percentages was minimal, as shown below:

Table 8: Revenue Requirement Increase/Decrease Comparison – Dakota Electric Rebuttal[13]

Rate Class	Dakota Electric Revenue Requirement	Department Revenue Requirement	Dakota Electric Rebuttal Revenue Requirement
Residential & Farm	5.29%	5.26%	5.26%
Small General Service	8.94%	8.61%	8.61%
Irrigation	(2.72%)	(0.53%)	(0.53%)
General Service	(0.26%)	(0.19%)	(0.19%)
C&I Interruptible	7.98%	7.99%	7.99%
Lighting	18.79%	18.63%	18.62%

In Heinen's Surrebuttal Testimony at P.7, the Department noted that the further adjustments identified in Dakota Electric's rebuttal testimony are de minimis and do not affect the Department's recommendation that the CCOSS is reasonable and that the Commission should approve the CCOSS with the changes noted in the Heinen's testimony for the Department and in Larson's Rebuttal for Dakota Electric.

12 DEA Ex. 53 at 10 (Larson Rebuttal).
13 *Id,* Table 2 at 10

D. ALJ Report

The ALJ recommended approval of the agreed upon Class Cost of Service Study with the three corrections identified in testimony.

E. PUC Staff Comment

Staff reviewed the record and concurs that the agreed upon CCOSS is reasonable.

F. Decision Alternatives

201. Approve Dakota Electric's corrected CCOSS as reasonable as recommended by the ALJ.

VII. Cost of Capital

PUC Staff: Jason Bonnett

A. Introduction

The rate of return (ROR) 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 member owners of Dakota Electric.

Dakota Electric, like any other business firm, needs capital to meet operating expenses and provide for future expansion of business. Capital comes in two forms: debt and equity.

Debt capital is money borrowed, on a short- or long-term basis, by the cooperative that must be paid back on time.

Equity capital for a cooperative is provided by the cooperative's members who are also its customers. By way of contrast, an investor-owned utility (IOU) must induce investors to take the risk of investing in the utility by offering an attractive return on equity.

An IOU must pay a return equal to the return that investors expect to earn on investments of comparable risk elsewhere. When investors buy the common stock of an IOU, they acquire the right to share in any dividends that the utility may declare in the future. The prospect of these dividends serves as an inducement to investors and is a critical component of the cost of common equity capital.

However, Dakota Electric is not an IOU, it is a cooperative and its ratepayers are also its investors. Unlike the case of an IOU, the required rate of return on Dakota Electric's equity is not determined by the opportunity cost of investing capital somewhere else; rather, it is determined by the need to finance the growth of the Company's rate base and maintain a sound capital structure.

The equity portion of the capitalization of Dakota Electric is collected from the utility's customers through the rates. When revenues exceed expenses, each customer/member of the cooperative is assigned a portion of the margin (that is, the portion of the amount by which revenues exceed expenses) on the basis of a customer's electricity consumption as a fraction of the total electricity consumed by all customers over the year. This margin is accumulated over the period of a year – called capital credits, also known as patronage capital – for each customer.

Dakota Electric does not pay traditional dividends but the accumulated capital credits are retired (or returned) to the customers/members when the cooperative is financially strong and the cumulative capital credit level is high.

The Commission has observed that the ROR, as applied to cooperatives, permits the development of sufficient margins to cover the cost of debt and equity capital.[14] Dakota Electric notes that the ROR method is intended to ensure that the Company's earnings are sufficient to cover the cost of debt (interest) and generate a fair return on the investment (equity) for the owners.[15] Because Dakota Electric is a cooperative, the "return on equity" is related to the retirement, or rotation, of patronage capital.

In the case of a typical electric utility, the weighted cost of capital is applied to the rate base to obtain the required rate of return. As the Department pointed out, for a typical electric utility, the test year rate base is equal to or only slightly different from total capitalization and, therefore, for a typical utility, the weighted cost of capital can be applied to the rate base directly.[16]

However, in Dakota Electric's case, there is a divergence between the test-year capitalization and rate base. As the Department noted, this is sometimes due to regulatory treatment of various assets that may or may not be included in the rate base.[17] Besides, unlike an IOU, Dakota Electric is required to pay patronage capital to its members, making such payments to equity holders similar to the interest payments to bond holders. Also, the Department noted, because Dakota Electric purchases equity capital only from its members, who are required to invest in the Company in order to receive electric service, and because Dakota Electric does not pay dividends out of its earnings, the Company's required rate of return on equity would be lower than its true cost of equity capital.[18]

The Department noted that because the overall ROR is applied to the rate base to produce the appropriate level of net income, the overall ROR on total capital must be adjusted to allow Dakota Electric to earn the same amount on its rate base as it would earn on its total capitalization. Further, to allow both bondholders and equity holders (Dakota Electric's members) to recover their investment costs, the return on total capital must be adjusted to recognize any difference between the rate base and total capitalization.[19]

This adjustment to Dakota Electric's weighted (or overall) cost of capital requires that the ROR be calculated as follows:

ROR = Weighted Cost of Capital * Rate Base Factor

The Rate Base Factor is defined as: Total Capitalization/Approved Rate Base.

If the Commission-approved rate base changes, the return on rate base will also change.

14 Findings of Fact, Conclusions of Law and Order in DEA's rate case (Docket No. E-111/GR-09-175), May 24, 2010, at 10.
15 DEA Ex. 6 at 14 (Larson Direct).
16 DOC Ex. 8 at 19-20 (Kundert Direct).
17 *Id*.
18 *Id*.
19 *Id*. at 20.

B. Reference to the Record

ALJ Report Findings of Fact 50-52
DEA Ex. 6 at 15 (Larson Direct)
DOC Ex. 2 at 12-24 (Kundert Direct)
DEA Ex. 53 at 2-3 (Larson Rebuttal)

C. Parties' Positions

Dakota Electric proposed the following test-year capital structure and return on type of capital in the instant rate case:[20]

Table 9: Dakota Electric's Proposed Rate of Return

Type of Capital	Proportion	Cost Rate	Weighted Cost
Long-Term Debt	46.92%	3.77%	1.77%
Common Equity	53.09%	4.14%	2.20%
Weighted Cost of Capital	100%		3.97%
Return on Rate Base		Rate Base Factor = 1.444	5.73%

In Direct Testimony, the Department recommended the following capital structure and rate of return.[21]

Table 10: Department's Proposed Rate of Return

Type of Capital	Proportion	Cost Rate	Weighted Cost
Long-Term Debt	36.57%	3.77%	1.38%
Common Equity	63.43%	4.03%	2.56%
Weighted Cost of Capital	100%		3.94%
Return on Rate Base		Rate Base Factor = 1.444	5.68%

In Rebuttal Testimony, Dakota Electric agreed with the Department's overall rate of return calculations and recommendations.[22]

D. ALJ Report

The ALJ did not explicitly express a position on this issue. However, since the ALJ report recommended adoption of the ALJ Report recommendations, the ALJ implicitly accepted the Department analysis.

20 DEA Ex. 6 at 15-16 (Larson Direct).
21 DOC Ex. 2 at 12-24 (Kundert Direct).
22 DEA Ex. 53 at 2-3 (Larson Rebuttal).

E. PUC Staff Comment

Staff reviewed the record and concurs that the agreed upon rate of return is reasonable and is consistent with how Dakota Electric's rate of return has been calculated and determined in previous DEA rate cases.

F. Decision Alternatives

301. Adopt the agreed upon rate of return.

VIII. Sales Forecast

PUC Staff: Ganesh Krishnan

A. Introduction

Both the Department and the ALJ recommend the Commission approve Dakota Electric's proposed energy sales volumes and budgeted customer counts. No other party commented on Dakota Electric's sales forecast.

B. Reference to the Record

ALJ Report Finding of Fact 59
DEA Ex. 38 entire (Workpaper 13, Sales History and Forecasted Test Year Normalization)
DEA Ex. 37 entire (Workpaper 12, Monthly Billed Sales 2009 – 2018)
DEA Ex. 53 at 5-7 (Larson Rebuttal)
DOC Ex. 3 at 1-4 (Beckett Direct)

C. Parties' Positions

In its Petition, Dakota Electric estimated a test-year sales forecast of 1,824,313,200 kWhs and corresponding revenue of $200,480,307. A detailed break-down of Dakota Electric's test-year customer count and sales forecast are given further below in Table 11.

In Direct Testimony, the Department noted that sales levels are an integral input in calculating Dakota Electric's rates and, therefore, the method of determining the sales levels must be reasonable.[23] After a thorough review, the Department concluded that Dakota Electric's data preparation for forecasting energy sales was reasonable.

The Department supported Dakota Electric's test-year sales estimate of all classes of customers, except the Residential & Farm Service (Rate Category 31) which accounts for nearly 46-percent of the Company's total test-year sales.

The Department's main concern was that, for Residential & Farm Service, Dakota Electric predicated the kWh use per customer on, among other variables, the number of customers themselves, in what appeared to be circular reasoning.

The Department re-estimated the kWh usage per customer for this class after excluding the number of customers as an explanatory variable. The Department's re-estimation resulted in use per customer of 698 kWh per month, as opposed to Dakota Electric's estimate of 697 kWh/month/customer[24] -- admittedly a very negligible difference.

However, applying the Department's calculations over the total number of Residential & Farm Service customers of 100,202, and over the 12 months of the test-year, yielded a test-year sales

23 DOC Ex. 3 at 2 (Beckett Direct).
24 Id. at 10.

figure of 697 kWh * 100,202 * 12 = 839,291,952 kWh. The corresponding test-year revenue figure for the Residential & Farm Service worked out to $114,480,647.

In sum, the Department's upward adjustment to Dakota Electric's test-year sales volume results in an increase in total test-year revenue of $148,612 (0.07 percent) and a corresponding increase in power costs of $100,178.[25]

D. Test-Year Customer Count and Sales Estimates

The following table shows Dakota Electric's test-year customer and sales forecast and the Department's adjustment to the Company's test-year sales forecast:

Table 11: Test-Year Customer, Energy Sales and Revenue

		Dakota Electric Association		Department	
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
Customer Class/Category	Customer Count	Energy Sales (kWh)	Revenue	Energy Sales (kWh)	Revenue
Residential & Farm Service (31)	100,202	838,089,528	$114,332,035	839,291,952	$114,480,647
Residential & Farm Demand Control (32)	15	378,000	$42,670		
Electric Vehicle (33)	88	300,960	$24,636		
Irrigation Service (36) Firm	8	162,528	$50,143		
Irrigation Service (36) Interruptible	384	7,801,344	$862,089		
Small General Service (41)	4,431	42,537,600	$5,799,609		
Security Lighting Service (44) - Closed to New	878	405,600	$102,369		
Street Lighting Service (44-2)	2,269	2,405,280	$466,293		
Street Lighting System (44-1)	470	521,040	$72,603		
Custom Residential Street Lighting (44-3)	12,190	6,750,960	$1,334,683		
LED Security Lighting Service (44 -4)	356	64,896	$31,109		
LED Street Lighting Member Owned (44-5)	11	8,712	$1,297		
LED Street Lighting (44-6)	597	202,152	$59,884		
Low Wattage Unmetered Service (45)	71	-	$8,520		
General Service (46)	2,750	462,000,000	$50,261,766		
Municipal Civil Defense Sirens (47)	66	-	$3,960		
Geothermal Heat Pump (49) Closed to New	3	172,800	$16,571		
Controlled Energy Storage (51)	1,718	10,308,000	$459,736		
Controlled Interruptible Service (52)	6,686	44,127,600	$2,634,418		
Residential & Farm Time of Day (53)	18	216,216	$29,057		
General Service Time of Day (54)	6	1,059,984	$126,286		
Standby Service (60)	1	-	$66,840		
Full Interruptible Service (70)	234	379,080,000	$23,144,467		
Partial Interruptible Service (71)	28	27,720,000	$2,151,089		

25 The Department's adjustment resulted in Dakota Electric's test-year sales volume of 1,825,515,624 kWhs and corresponding revenue of $200,628,919.

Table 11: Test-Year Customer, Energy Sales and Revenue

		Dakota Electric Association		Department	
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
Cycled Air Conditioning Service (80)	41,880	5,075,000	-$1,625,193		
Wellspring			$23,370		
Rate Schedules Total	108,165	1,824,313,200	$200,480,307	1,825,515,624	$200,628,919

In Rebuttal Testimony, Dakota Electric stated that the Department's recommended test year sales volume for the Residential and Farm Service rate class was within 0.15% of Dakota Electric's forecast for this class. Dakota Electric further noted that given this high degree of correlation, it agrees to the adjusted residential test-year sales volumes and resulting adjustment to revenue and test year cost of purchased power.

E. ALJ Report

The ALJ's finding regarding test-year sales forecast is contained in paragraph 59 (quoted below without footnotes):

> ¶ 59. The Department analyzed the test year sales volumes and customer counts included in Dakota Electric's Initial Filing and recommended their use in calculating test year revenues with the exception of the Residential and Farm Service class. For that class, the Department recommended use of its econometric model, which resulted in an increase in sales to the class, increasing revenues by $148,612 and increasing the associated cost of purchased power by $100,178. Given the high degree of correlation between the Department and Cooperative forecasts, Dakota Electric agreed to the Department's recommendation on this matter.

F. PUC Staff Comment

The revenue and expense adjustments resulting from the Department's re-estimation of the Residential and Farm Service rate class energy use constitute the largest adjustments to DEA's pro forma test-year data.

G. Decision Alternatives

401. Approve Dakota Electric's proposed test-year customer count and energy sales volumes for all classes of customers with the exception of the Residential and Farm Service class. For the Residential and Farm Service class, approve the adjustments recommended by the Department and accepted by Dakota Electric.

IX. Rate Design

PUC Staff: Kevin O'Grady

A. Introduction

Rate Design is the second step of a two-step ratemaking process. The purpose of rate design is to assign revenue responsibilities to customer classes. Once the appropriate revenue level, or revenue requirement is determined, the Commission must determine the rates used for charging the utility's customers for service. In setting rates, the Commission should be aware that rates must be just and reasonable[26] and an important aspect of reasonable rates is their design. It should be noted also that rate design is largely a quasi-legislative function, involving policy decisions. A key purpose of rate design is determination of which customer classes should be apportioned responsibility for paying the costs that are reflected in the revenue requirement and what kinds of rates should be used to recover those costs.

A detailed description of Dakota's current and initially proposed rate structure is presented in Tables 10 to 27 of the Larson Direct Testimony and summarized in Larson Direct Exhibit DEA-6, pages 1 to 6. DOC raised concerns with only a few rates and, ultimately, Dakota agreed to DOC's proposed changes. OAG initially raised concerns regarding residential and small business monthly customer charges, but those issues were resolved between the parties. The ALJ found Dakota's rate design, as modified by DOC's recommendations, to be reasonable.

B. Reference to the Record

DEA Ex. 6 at 39-62 (Larson Direct)
DEA Ex. 53 at 10-13 (Larson Rebuttal)
DOC Ex. 6 at 7-18 (Peirce Direct)
DOC Ex. 7 at 1-6 (Peirce Rebuttal)
Compliance Filing, Updated Exhibit DEA-6 at 1-6
ALJ Report Findings of Fact 77-79

C. Parties' Positions

In its Petition, Dakota Electric proposed rates for 25 main rate classes, each class comprising a number of rates. Dakota Electric lists both present and proposed rates in Larson Exhibit DEA-6, pp. 1-6. In Direct Testimony, pages 39-62, Larson provides a discussion in support of Dakota Electric's proposal. The following discussion focuses on selected rate proposals.

1. Apportionment of Class Revenue Responsibility

Dakota Electric stated that its initial proposed revenue apportionment was based on the results of its CCOSS, along with other rate design objectives, including the need to avoid abrupt changes and its desire to achieve member acceptance. Table 12 presents Dakota Electric's apportionment of its current and initially-proposed revenue requirements. Dakota Electric proposed to increase the Residential & Farm revenue requirement by 4.42 percent

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26 Minn. Stat. §§ 216B.03, 216B.07.

(approximately $5 million), to increase General Service by 1.84 percent (approximately $926 thousand), to increase Lighting by 18.37 percent (approximately $380 thousand) and to increase Interruptible by 6.56 percent (approximately $1.66 million). Residential & Farm customers would be allocated over 58 percent of the proposed revenue increase. Dakota Electric witness Larson discussed the cost study underlying its proposed allocation on pages 20-32 of the Direct Testimony.

Table 12. Forecasted Customers, Forecasted Sales, Test Year Revenue, Proposed Revenue and Proposed Revenue Increase, by Rate Class[1]

Rate Class (Schedule)	Forecasted Number of Consumers	Forecasted Sales (kWh)	Test Year Revenue ($)	Proposed Revenue ($)	Proposed Increase ($)	Proposed Increase (%)
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Res & Farm (31, 32, 53)	100,235	838,683,744 *[45.97%]*[3]	114,403,762 *[57.06%]*[3]	119,464,523 *[57.12%]*[3]	5,060,761 *[58.52%]*[3]	4.42
Elec Vehicle (33)	88	300,960 *[0.02]*	24,636 *[0.01%]*	26,505 *[0.01%]*	1,869 *[0.02%]*	7.59
Irrigation (36)	392	7,963,872 *[0.44%]*	912,232 *[.46%]*	933,637 *[0.45%]*	21,405 *[0.25%]*	2.35
Small Gen Service (41)	4,431	42,537,600 *[2.33%]*	5,799,609 *[2.89%]*	6,197,337 *[2.96%]*	397,728 *[4.60%]*	6.86
Gen Service (46, 54)	2,756	463,059,984 *[25.38%]*	50,388,052 *[25.13%]*	51,314,509 *[24.54%]*	926,457 *[10.71%]*	1.84
Lighting (44, 44-1 - 44-6)	16,771	10,358,640 *[0.57%]*	2,068,238 *[1.03%]*	2,448,090 *[1.17%]*	379,852 *[4.39%]*	18.37
Low Watt Unmet (45)	71	-	8,520 *[0.00%]*	8,946 *[0.00%]*	426 *[0.00%]*	5.00
Muni Sirens 47)	66	-	3,960 *[0.00%]*	3,960 *[0.00%]*	0	0
Geo Heat Pump (49)	3	172,800 *[0.01%]*	16,571 *[0.01%]*	17,798 *[0.01%]*	1,227 *[0.01%]*	7.40
Controlled Storage (51)	1,718	10,308,000 *[0.57%]*	459,736 *[0.23%]*	502,001 *[0.24%]*	42,265 *[0.49%]*	9.19
Controlled Service (52)	6,686	44,127,600 *[2.42%]*	2,634,418 *[1.31%]*	2,784,452 *[1.33%]*	150,034 *[1.73%]*	5.70
Standby (60)	1		66,840 *[0.03%]*	74,160 *[0.04%]*	7,320 *[0.08%]*	10.95
Interruptible (70, 71)	262	406,800,000 *[22.30%]*	25,295,556 *[12.62%]*	26,954,388 *[12.89%]*	1,658,832 *[19.18%]*	6.56
Cycled A/C (80)	41,880	-	(1,625,193) *[-0.81%]*	(1,625,193) *[-0.78%]*	1	0
Wellspring	-	-	23,370 *[0.01%]*	23,370 *[0.01%]*	0	0
Total	108,165[2]	1,824,313,200	200,480,307	209,128,483	8,648,177	4.31

[1] See DEA Ex. 5 at 2 (Interim Rate Schedules) and DEA Ex. 6 at 7 (Larson Direct).

Table 12. Forecasted Customers, Forecasted Sales, Test Year Revenue, Proposed Revenue and Proposed Revenue Increase, by Rate Class[1]						
Rate Class (Schedule)	Forecasted Number of Consumers	Forecasted Sales (kWh)	Test Year Revenue ($)	Proposed Revenue ($)	Proposed Increase ($)	(%)
(a)	(b)	(c)	(d)	(e)	(f)	(g)
[2] To account for consumers that take more than one service this total excludes figures for Rate Classes 44, 44-1 to 44-6, 45, 47, 49, 51, 52, and 80. [3] Italicized figures in square brackets *[n.nn%]* indicate the percent of the contribution of the cell to the column total.						

The Department supported Dakota Electrics's proposed allocation stating …

> DEA has appropriately balanced moving those customer classes that are below cost closer to the cost of serving them, while limiting the revenue increases to classes currently above cost. In addition, the increase to the residential class with its potential impact on low-income customers is held very close to the overall proposed increase. Finally, the 18 percent increase in Lighting class revenues, while sizeable, reflects an increase on a relatively small revenue base.[27]

Should the Commission approve a different level of revenue requirement than the level proposed by Dakota Electric, the Department recommends proportionally adjusting the revenue requirement to reflect its recommended apportionment.[28]

a. ALJ Report

The ALJ stated ...

> 75. The Department reviewed the Cooperative's proposed revenue apportionment and, after considering both cost and non-cost factors, agreed with Dakota Electric's proposed revenue apportionment, and that this apportionment be reduced proportionally if the Commission approves a lower overall revenue increase than was requested in Dakota Electric's Initial Filing.
>
> 76. The Administrative Law Judge finds that the revenue apportionment proposed by the Cooperative and agreed to by the Department, proportionally reduced to reflect the financial adjustments discussed above, is reasonable, supported by the record and should be adopted.

b. PUC Staff Comment

Staff believes the parties have negotiated, and the ALJ has recognized, that this is a reasonable apportionment of responsibility for DEA's revenue requirement to DEA's customer classes.

27 DOC Ex. 6 at 7 (Peirce Direct).
28 *Id*.

c. Decision Alternatives

501. Approve the revenue apportionment recommended by the ALJ.

2. Customer Charges

Dakota Electric proposes changes to a number of monthly fixed charges based on its costs.[29] Specifically, Dakota Electric states:

> 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 some progress toward cost recovery of this component in this rate case. We note, however, that this modest 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.[30]

Notably, Dakota Electric proposed to raise the monthly fixed charge for Residential & Farm Service by $1.00, from $9.00 to $10.00.

The Department recommended approval of Dakota Electric's proposed customer charges, except for three classes: Irrigation, General Service, and Time of Day. In each case, the Department recommended that the Company increase the monthly rates by $3.00 (from $30 to $33 for Irrigation; from $34 to $37 for General Service; and from $36 to $39 for Time of Day). The Department reasoned that its proposed rates move rates closer to costs.[31]

The Department supported Dakota Electric's proposed increase of $1.00 per month for residential customer charges, as it better reflects costs.

a. ALJ Report

The ALJ Report recommended that the Commission accept the resolution reached by the parties.

b. PUC Staff Comment

Staff finds the agreed upon customer charges to be reasonable.

c. Decision Alternatives

502. Approve the customer charges as recommended by the ALJ.

[29] DEA Ex. 6 at 41-59 (Larson Direct) and DEA Ex. 7 at 1-5 (Statement of Operations – Present Rates).
[30] DEA Ex. 6 at 42 (Larson Direct).
[31] DOC Ex. 6 at 7-10 (Peirce Direct).

3. Residential Time of Day Tariff

Dakota Electric proposes to raise its Residential and Farm Time of Day rates to reflect increased costs.[32]

The Department recommended approval of Dakota Electric's Residential Time of Day Tariff to reflect the wholesale rates at which the Company purchases from Great River Energy.[33]

a. ALJ Report

The ALJ Report recommended approval of the proposed Residential Time of Day Tariff.

b. PUC Staff Comment

Staff concludes the agreed upon Residential Time of Day Tariff to be reasonable.

c. Decision Alternatives

503. Approve the Residential Time of Day Tariff as recommended by the ALJ.

4. Standby Service

Dakota Electric proposes, in keeping with a Commission-approved methodology, to increase primary and secondary distribution reservation fees (respectively, from \$3.28/kW to \$3.89/kW, and from \$3.51/kW to \$4.02/kW), and to decrease its substation distribution reservation fee (\$0.90/kW to \$081/kW).[34]

The Department recommends approval of Dakota Electric's proposed Standby rates as consistent with the Commission's requirements in Docket 15-115.[35]

a. ALJ Report

The ALJ Report recommended approval of the proposed Standby rates.

b. PUC Staff Comment

Staff concludes that the agreed upon Standby rates are reasonable.

c. Decision Alternatives

504. Approve the Standby rates as recommended by the ALJ.

[32] DEA Ex. 6 at 55 (Larson Direct).
[33] DOC Ex. 6 at 11-12 (Peirce Direct).
[34] DEA Ex. 6 at 56 (Larson Direct).
[35] DOC Ex. 6 at 13 (Peirce Direct).

5. Electric Vehicle Rates

Dakota Electric proposes to make its EV pilot program into a permanent offering. Dakota Electric's EV customers would have ongoing access to this option.[36] Dakota Electric also proposes to increase its On-Peak and Off-Peak rates. On-Peak rates would increase from $0.4144 to $0.4421 per kWh. Off-Peak rates would increase from $0.0674 to $0.0756 per kWh.[37]

The Department supports Dakota Electric's proposal to make its EV pilot program into a permanent offering. The Department expects the demand for EV service to increase.[38]

In addition, the Department supports Dakota Electric's proposal to increase its On-Peak and Off-Peak rates to reflect higher costs from the Company's wholesale provider, Great River Energy.[39]

a. ALJ Report

The ALJ Report recommended approval of the proposed Electric Vehicle rates.

b. PUC Staff Comment

Staff concludes that the agreed upon Electric Vehicle rates to be reasonable.

c. Decision Alternatives

505. Approve the Electric Vehicle rates as recommended by the ALJ.

6. Line Extension Charges

Dakota proposes to modify its line extension charges. Currently, Dakota provides a base footage allowance of 75 feet for $500.00 plus $8.30/foot for extensions above 75 feet. This rate applies to all individual residential line extensions. Dakota proposes to change to a base fee of $1,000.00 plus $11.00 per foot for each foot of the extension (with no free footage allowance). Dakota would refund the amount paid for individual residential line extensions that exceed actual costs for the extension. Dakota states: "This proposal for individual residential line extension charges 1) better reflects costs recovered through base rates, 2) helps ensure that new members are paying a more reasonable share of line extension costs, 3) limits payments to no more than actual costs, while 4) reducing the cost burden on existing ratepayers."[40]

DOC supports DEA's proposed Line Extension Charges.[41]

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[36] DEA Ex. 6 at 44 (Larson Direct).
[37] *Id.* at 45.
[38] DOC Ex. 6 at 14 (Peirce Direct).
[39] *Id.*
[40] DEA Ex. 6 at 61 (Larson Direct).
[41] DOC Ex. 6 at 15-17 (Peirce Direct).

a. ALJ Report

The ALJ Report recommended approval of the proposed Line Extension charges.

b. PUC Staff Comment

Staff concludes that the agreed upon Line Extension charges to be reasonable.

c. Decision Alternatives

506. Approve the Line Extension charges as recommended by the ALJ.

7. Service and Connection Charges

Dakota Electric proposes changes to an array of special fees as a result of its cost analysis and to eliminate a redundancy in its Rate Book.[42]

The Department supports Dakota Electric's proposed Service and Connection charges.[43]

a. ALJ Report

The ALJ Report recommended approval of the proposed service and connection charges.

b. Staff Comment

Staff concludes that the agreed upon service and connection charges to be reasonable.

c. Decision Options

507. Approve the service and connection charges as recommended by the ALJ.

[42] DEA Ex. 6 at 60 (Larson Direct).
[43] DOC Ex. 6 at 17-18 (Peirce Direct)

X. General Housekeeping and Compliance Issues

All of the compliance filing requirements in the decision alternatives are standard rate case compliance items. These requirements ensure that Dakota Electric files various financial and rate design schedules that reflect the Commission's decision, revised tariff sheets, a draft customer notice, and a new base Resource and Tax Adjustment. An interim rate refund plan may not be necessary if the approved final rates are higher than interim rates.

Staff also recommends the Commission include a set of financial summaries for Dakota Electric in its order in this docket that includes: a schedule showing the calculation of the Company's authorized cost of capital, a rate base summary, an operating income statement summary, a gross revenue deficiency calculation, and a statement of total allowed revenues.

Decision Alternatives – General Housekeeping and Compliance Issues

901. State that the final order in this docket shall contain summary financial schedules including: a calculation of Dakota Electric's authorized cost of capital, a rate base summary, an operating income statement summary, a gross revenue deficiency calculation, and a statement of the total allowed revenues. Direct parties to work with Commission staff to prepare such schedules for inclusion in the Order, should modifications be necessary to reflect the Commission's final decision.

902. Require Dakota Electric to make the following compliance filings within 30 days of the date of the final order in this docket:

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

      i. Breakdown of Total Operating Revenues by type;

      ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:
      (1) Total revenue by customer class;
      (2) Total number of customers, the customer charge and total customer charge revenue by customer class; and
      (3) For each customer class, the total number of energy and demand related billing units, the per unit energy and demand cost of energy, and the total energy and demand related sales revenues.

      iii. Revised tariff sheets incorporating authorized rate design decisions;

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

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

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

d. Direct Dakota Electric to file a computation of the base DSM & Conservation Recovery rate, based upon the decisions made herein for inclusion in the final Order. Direct Dakota Electric to file a schedule detailing the DSM & Conservation Recovery tracker balance at the beginning of interim rates, the revenues (both base and the Resource and Tax Adjustment rate recovery) and costs recorded during the period of interim rates, and the DSM & Conservation Recovery tracker balance at the time final rates become effective.

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

903. Authorize comments on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Dakota Electric's proposed customer notice.

XI. Decision Alternatives

ALJ Findings of Fact, Conclusions of Law, and Recommendations

1. Accept and adopt the ALJ's Findings of Fact, Conclusions of Law and Recommendations

2. Accept and adopt the ALJ's Findings of Fact, Conclusions of Law and Recommendations with the limited exceptions proposed by the Department and updated correction proposed by staff.

3. Accept and adopt the ALJ's Findings of Fact, Conclusions of Law and Recommendations with modification to one or more of the issues listed below.

4. Reject the ALJ's Findings of Fact, Conclusions of Law and Recommendations

Financial Issues

Organization and Membership Dues and Lobbying Expenses

101. Disallow Dakota Electric recovery of $10,475 of NRECA organization and membership dues. (Department Direct, Parties Agreed, ALJ)

102. Disallow Dakota Electric recovery of $24,367 of MREA organization and membership of dues. (Department in Surrebuttal, Parties Agreed, ALJ)

103. Allow Dakota Electric to recover $80,575 of NRECA organization and membership dues. (Dakota Electric Initial Filing)

104. Allow Dakota Electric to recover $152,010 of MREA organization and membership dues. (Dakota Electric Initial Filing)

Travel Expenses

105. Disallow recovery of $3,548.86 in travel expenses. (OAG Direct, Parties agreed, ALJ)

106. Allow Dakota Electric to recover all travel expenses related to Touchstone Energy Meetings. (Dakota Electric Initial Filing)

Community Events

107. Disallow recovery of $7,964.55 in Community Events expenses. (OAG Direct, Parties agreed, ALJ)

108. Allow Dakota Electric to recover $15,929.10 in Community Events expenses. (DEA Initial Filing)

Property Tax Rates

109. Order that the $8,227 in wholesale margin net income be removed from the revenue requirement calculation. (Department Direct, Parties agreed, ALJ)

110. Order that the $8,227 in wholesale margin net income be included in the revenue requirement calculation. (Dakota Electric Initial Filing)

Sales Revenue and Purchased Power Expense

111. Approve the methodology used to calculate the cash working capital included in rate base. (Department Direct, Parties agreed, ALJ)

Meter Plant Balance

112. Allow adjustments credits related to Meter Plant Balance to flow through the AGI Rider. (DEA Rebuttal, Parties agreed, ALJ)

113. Do not allow adjustments credits related to Meter Plant Balance to flow through the AGI Rider.

Class Cost of Service Study

201. Approve Dakota Electric's corrected CCOSS as reasonable as recommended by the ALJ.

Cost of Capital

301. Adopt the agreed upon rate of return.

Sales Forecast

401. Approve Dakota Electric's proposed test-year customer count and energy sales volumes for all classes of customers with the exception of the Residential and Farm Service class. For the Residential and Farm Service class, approve the adjustments recommended by the Department and accepted by Dakota Electric.

Rate Design

Revenue Apportionment

501. Approve the revenue allocation as recommended by the ALJ.

Customer Charges

502. Approve the customer charges as recommended by the ALJ.

Residential Time of Day Tariff

503. Approve the Residential Time of Day Tariff as recommended by the ALJ.

Standby Service

504. Approve the Standby rates as recommended by the ALJ.

Electric Vehicle Rates

505. Approve the Electric Vehicle rates as recommended by the ALJ.

Line Extension Charges

506. Approve the Line Extension charges as recommended by the ALJ.

Service and Connection Charges

507. Approve the service and connection charges as recommended by the ALJ.

General Housekeeping and Compliance Issues

901. State that the final order in this docket shall contain summary financial schedules including: a calculation of Dakota Electric's authorized cost of capital, a rate base summary, an operating income statement summary, a gross revenue deficiency calculation, and a statement of the total allowed revenues. Direct parties to work with Commission staff to prepare such schedules for inclusion in the Order, should modifications be necessary to reflect the Commission's final decision.

902. Require Dakota Electric to make the following compliance filings within 30 days of the date of the final order in this docket:

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

        ii. Breakdown of Total Operating Revenues by type;

        ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:
        (1) Total revenue by customer class;
        (2) Total number of customers, the customer charge and total customer charge revenue by customer class; and
        (3) For each customer class, the total number of energy and demand related billing units, the per unit energy and demand cost of energy, and the total energy and demand related sales revenues.

        iv. Revised tariff sheets incorporating authorized rate design decisions;

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

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

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

d. Direct Dakota Electric to file a computation of the base DSM & Conservation Recovery rate, based upon the decisions made herein for inclusion in the final Order. Direct Dakota Electric to file a schedule detailing the DSM & Conservation Recovery tracker balance at the beginning of interim rates, the revenues (both base and the Resource and Tax Adjustment rate recovery) and costs recorded during the period of interim rates, and the DSM & Conservation Recovery tracker balance at the time final rates become effective.

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

903. Authorize comments on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Dakota Electric's proposed customer notice.