MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
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October 1, 2015

Mr. Thorvald A. Nelson
Holland & Hart, LLP
6380 South Fiddlers Green Circle, Suite 500
Greenwood Village, Colorado 8011

Re: General Electric Rate Application
Docket No. D2015.6.51

Dear Mr. Nelson:

Enclosed please find Montana-Dakota Utilities Co.'s responses to the Montana Large Customer Group's data request dated September 16, 2015.

Sincerely,

Tamie A. Aberle
Director of Regulatory Affairs

Attachments
cc: Service List

Montana-Dakota Utilities Co.
Docket No. D2015.6.51
Service List

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MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-001
Regarding: MDU'S Workpapers
Witness:

To the extent not otherwise provided in the Company's response to Montana Public Service Commission data request PSC-001, please provide all workpapers utilized in the preparation of the Company's filing in this case, in Excel format where applicable, with all formulas and links intact.

Response:

The requested information was provided in response to PSC-001 and PSC-002.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-002
Regarding: MDU's Revenue Requirement
Witness:

To the extent not otherwise provided in the Company's response to Montana Public Service Commission data request PSC-001, please provide a working copy of the Company's revenue requirement model(s) and all supporting workpapers in Excel format with all formulas intact. If there is any supporting documentation on the use/operation of these models, please include the documentation with this response.

Response:

The requested information was provided in response to PSC-001 and PSC-002.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-003
Regarding: Updated Information (as applicable)
Witness:

To the extent the Company files corrections, revisions, amendments, supplemental information and/or errata to its originally filed case, please provide all updated materials including the Company's testimony, exhibits, workpapers and models in an electronic format with working formulas included where applicable

Response:

The Company has not filed any corrections, revisions, amendments or supplemental information to its originally filed case.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-004 RE: Cost of Service
Witness: Cardwell/Aberle

Please provide any prior Commission Orders supporting the use of the results of both an embedded class cost of service study and a marginal cost of service study.

Response:

The witness is not aware of any recent Commission Order in Montana-Dakota's electric cases regarding the use of the results of an embedded study and/or marginal cost of service study.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-005 RE: Cost of Service
Witness: Cardwell/Aberle

Please explain how the Company uses the results of its embedded cost of service study and its marginal cost of service study to specifically develop the proposed increases for each rate class. How does the Company weight these two studies in this determination (class rate increases)?

Response:

Montana-Dakota relied primarily on the embedded class cost of service study in its development of the proposed increase for each rate class.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-006 Regarding: Cost of Service
Witness: Cardwell

Please provide any prior Commission Orders adopting the use of an AED methodology to allocate costs in an embedded class cost of service study.

Response:
Recent Commission Orders in Montana-Dakota's electric rate cases have not specifically addressed the use of the AED methodology to allocate demand costs to the different rate classes of customers.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-007 Regarding: Cost of Service
Witness: Cardwell

Please identify the production demand allocation methodology used by MDU in any of its other jurisdictions during the past 5 years in a class cost of service study. Provide the case or docket number, the jurisdiction and copies of any supporting MDU testimony.

Response:

2010 – North Dakota, PU-10-124, Average Excess Demand (AED)
2015 – South Dakota, EL15-024, Average Excess Demand (AED)

Please see LCG – 007 Attachment A pages 4 and 5 for supporting MDU Testimony in Case PU-10-124 and Attachment B pages 5 and 6 for supporting MDU Testimony in Case EL15-024.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the South Dakota Public Utilities Commission

Docket No. EL15-____

Direct Testimony
of
Sara J. Cardwell

Q. Would you please state your name and business address?

A. Yes. My name is Sara J. Cardwell, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Manager, Regulatory Affairs--Pricing & Tariffs for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your responsibilities as Manager, Regulatory Affairs-Pricing & Tariffs?

A. My responsibilities include the preparation of the embedded class cost of service studies, rate designs and miscellaneous tariff revision filings. I also administer utility tariffs and rules and regulations effective for each of the jurisdictions in which Montana-Dakota provides utility service.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Wisconsin-Stout with a Bachelor of Science degree in Business Administration and received my Masters in Business Administration from the University of Portland. I have worked for PacifiCorp, Portland General Electric Company, Xcel Energy and the

North Dakota Public Service Commission. I started working in my current position at Montana-Dakota in 2014.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before the Public Service Commissions of North Dakota and Montana as well as the California and Idaho Public Utilities Commissions, the Oregon Public Utility Commission and the Washington Utilities and Transportation Commission.

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

A. The purpose of my testimony is to present the results of the class cost of service study.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Statement N.

Q. Would you please explain the embedded class cost of service study contained in Statement N?

A. Yes. Statement N, Schedule N-1, pages 1 through 10 provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the overall requested rate of return of 7.588 percent is to be earned for the demand, energy and customer cost components of each rate schedule. The rate of return before allocation of the requested increase is also shown on Statement N. As an example, the resulting rate of return on the rate base allocated to residential customers under Residential Service Rate 10 is 3.193 percent and a revenue increase of approximately $1,385,000 would be necessary to bring the residential rate of return to the overall average return.

Statement N, page 1 also indicates that the customer related component associated with providing service to the residential class is $20.45 per month with the demand and energy components comprising the remaining requirement at 9.2 cents per Kwh. This same information is shown for each rate schedule on pages 2 through 10 of Statement N.

A summary of the results by the major rate classifications, Residential, Small General Service, Large General Service, Municipal Pumping and Lighting is provided in Statement N, N-1, pages 11 and 12.Statement N, Schedule N-2, pages 1 through 110 is a detailed report of the rate base, income statement and pro forma adjustments as allocated to each rate schedule. The allocation factor applied to the total South Dakota electric amount is shown on each line item.

Statement N, Schedule N-3 provides a list of the allocation factors used to allocate the total South Dakota electric amount to each class and cost component as referenced in Schedule N-2.

Q. What were the results of the embedded cost of service study?

A. The overall South Dakota electric rate of return based on the 2014 pro forma test period presented by Mr. Jacobson is 3.400 percent. The returns by rate schedule as shown on Statement N, Schedule N-1, pages 1 through 10 are as shown below:

Rate Schedule	ROR
Residential Service – Rate 10	3.193%
Small Primary General Service – Rate 20	-5.774%
Small Sec. General Service – Rate 20	5.180%
Irrigation Service – Rate 25	-7.457%
Large Sec. General Service – Rate 30	3.754%
Space Heating – Rate 32	-3.892%
Municipal Pumping Service – Rate 48	-0.430%
Outdoor Lighting Service – Rate 24	-10.353%

Company Owned Streetlighting – Rate 41	7.534%
Municipal Owned Streetlighting – Rate 41	2.077%

Q. How did you determine what costs should be assigned to each class of customers?

A. The starting point was classifying the functionalized costs by FERC account for all rate base and income statement items as demand, energy or customer related based on the component of service being provided. Demand-related costs are costs that vary with the Kw demand imposed by the customer, energy-related costs vary with the energy or Kwh the customer uses and customer-related costs are fixed costs driven by the number of customers served.

Next the plant, expense and revenue items that were identified as directly related to a specific class of customers were directly assigned to the appropriate class. Finally, the remaining costs were allocated using the various allocation factors shown on Statement N, Schedule N-3.

Q. Would you please provide an overview of the allocation process including the rationale underlying the choice of allocation factors?

A. Yes. I will start with the plant in service items on the rate base schedule starting on Statement N, Schedule N-2, page 1. The plant allocation serves as the basis for allocating many of the other rate base items. The investment in production related plant items was allocated on an average and excess demand (AED) allocator to account for the contribution of each class based on a combination of the classes' average demand and non-coincident peak demands. The AED factor is comprised of the sum of the average demand of each class and the difference between the total system peak demand and the average demand as allocated to each class based on the non-coincident demand in excess of the average demand. The production investment related to the Company's wind facilities was allocated on a factor based 84.5 percent on the energy allocation factor (Factor No.1) and 16.5 percent on the AED allocator to reflect the fact the wind facilities are primarily an energy resource. The investment in transmission plant related items was allocated on the AED factor.

Turning now to the distribution plant investment; each distribution plant account is analyzed and allocated based on the cause for the investment. Station equipment and the associated land and land rights are allocated on the non-coincident peak demand of each class, representing the maximum demand on the system. The next set of plant items - Poles, Towers & Fixtures; Overhead Conductors & Devices; and Underground Conduit & Devices were classified as customer and demand related based on an analysis of the minimum and normal system design for a typical distribution system, with the minimum system representing the percentage of the plant accounts assigned to the customer component, and the remainder classified as demand related. Based on this analysis, the minimum investment necessary to connect a customer was determined to be 85 percent of the total required investment. The amounts classified as customer related were then allocated to each rate class based on the number of customers served in each rate class, or Factor No. 8.0. The dollar value of the Poles, Towers & Fixtures; Overhead Conductors & Devices; and Underground Conduit & Devices classified as demand related (15 percent of the total) was allocated to each rate class based on the maximum demand of each rate class (non-coincident peak Factor No. 4.1). The investment in Line Transformers was also classified as customer and demand related. The percentage assigned to the customer component was determined based on the minimum intercept method which seeks to identify the portion of the transformer investment associated with a hypothetical no-load condition. Based on an analysis of the type and size of transformers, representing the minimum equipment necessary to provide service to secondary system customers, the zero intercept was determined to be $1,604. Applying this amount to the number of transformers resulted in a customer component of 77 percent with the remaining 23 percent classified as demand related. The classified costs were allocated on weighted customer transformers (Factor 11) and the non-coincident secondary demand factor (Factor 5) accordingly.

The four remaining distribution accounts; Services, Meters, Installation on Customer Premises and Street Light & Signal System are all related solely to a customer connection and were classified as customer related. Services were allocated to the rate classes based on a factor representing services weighted by customer class derived by comparing the installed cost per service for each rate class to the cost necessary to serve Residential service customers. The weights were then applied to the number of customers in each rate class. The same process was used to fashion an allocation based on weighted meter costs (Factor No. 6) for allocating the embedded investment in meters. The investment in Installation on Customer Premises was directly assigned to Outdoor Lighting and the investment in Street Light & Signal Systems was directly assigned to Municipal Lighting. The allocation of the remainder of the rate base items is self explanatory with the allocation factor noted for each line item.

Q. Would you please continue with an explanation of the income statement items in the class cost of service study?

A. Yes. The allocation of the income statement items starts on Statement N, Schedule N-3, page 3 with the allocation of revenues. As shown, revenues are directly assigned based on the revenues produced under each rate schedule.

Operation and maintenance expenses consisting of fuel, purchased power costs, transmission, distribution and administrative and general expenses are shown starting at Schedule N-2, page 4. The production expenses are classified as demand and energy related with the fuel, purchased power and variable production expenses classified as energy and allocated based on the energy requirements of each class. The other production expenses and purchased capacity costs are classified as demand costs and allocated on the same demand allocator used to allocate production plant costs. Transmission operation and maintenance costs are also classified as demand related and allocated on the AED demand allocator (Factor No. 2). Customer Accounts Expense and Customer Service and Information Expenses were allocated on a weighted customer factor (Factor No. 12) based on the estimated cost of meter reading and customer billing for each class relative to the residential weighting set equal to 1.0. The remaining operation and maintenance expenses are allocated based on cost causation and typically follow the plant investment previously described in the rate base section. The remainder of the income statement reflects the allocation of depreciation expense, taxes other than income and income taxes as denoted by each line item.

Q. For what purpose has the embedded class cost of service study been used?

A. The study results have been used for the purpose of analyzing the various components comprising the total rate applicable to each customer class. In addition to providing the rate of return provided by each customer class, the class study provides the basis for the customer related costs to be collected under the Basic Service Charge component of each rate schedule and the demand related costs to be collected under the Demand Charge component of those rate schedules where demand is metered and measured for billing purposes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-10____

Direct Testimony
of
Tamie A. Aberle

Q. Would you please state your name and business address?

A. Yes. My name is Tamie A. Aberle, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Pricing & Tariff Manager in the Regulatory Affairs Department of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your responsibilities as the Pricing & Tariff Manager?

A. My responsibilities include the preparation of rate design and miscellaneous tariff revision filings to ensure that the applicable revenue requirements are properly recovered from various customer classes via applicable rate forms. I also administer utility tariffs and rules and regulations effective in each of the jurisdictions in which Montana-Dakota provides utility service.

Q. Would you please outline your educational and professional background?

A. I graduated from Moorhead State University, Moorhead, Minnesota in 1982 with a Bachelor of Science degree in Accounting. I began my career with Montana-Dakota in 1983 in the Regulatory Affairs Department, I was promoted to Rate Administration Supervisor in 1990 and achieved my present position in May 1999.

Q. Have you testified in other proceedings before regulatory bodies?

A. Yes. I have previously presented testimony before this Commission, the Public Service Commissions of Montana and Wyoming, and the Public Utilities Commissions of Minnesota and South Dakota.

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

A. The purpose of my testimony is to present the results of the class cost of service study and to address the effect of the proposed revenue requirement, as identified by Ms. Mulkern in her direct testimony, on each of the Company's electric rates, including how the distribution of the revenue requirement was made among the various customer classes served. In addition, my testimony will discuss the extent to which Montana-Dakota is proposing changes in rate design and proposed tariff changes.

Q. What statements and exhibits are you sponsoring in this proceeding?

A. I am sponsoring Statement O, Statement P and Exhibit No. ___ (TAA-1) through Exhibit No.___(TAA-2). I also sponsor the proposed rate schedules provided in Appendix B to the Application, other than the Fuel and Purchased Power Adjustment Rate 58 schedule sponsored by Ms. Mulkern.

Q. What is the total revenue effect of the proposed electric rate changes?

A. The proposed rates will produce additional revenues of $15,396,303 or an increase of 13.9% annually based on projected 2010 electric consumption. Exhibit No. ____ (TAA-1) represents summaries by rate classification of the proposed final revenue increase. The exhibit shows the rate class and the revenues calculated under the present and proposed rates. The amount and percentage increase is also shown for the proposed revenue increase.

Q. Would you please explain the embedded class cost of service study contained in Statement O?

A. Yes. Statement O provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the overall requested rate of return of 9.091% is to be earned for the demand, energy and customer cost components of each rate schedule. The rate of return before allocation of the requested increase is also shown on Statement O. As an example, the resulting rate of return on the rate base allocated to residential customers under Residential Service Rate 10 is 3.386% and a revenue increase of approximately $12,693,000 would be necessary to bring the residential rate of return to the overall average return. Statement O, page 1 also indicates that the customer related component associated with providing service to the residential class is $16.40 per month with the demand and energy components comprising the remaining requirement at $0.075 per Kwh. This same information is shown for each rate schedule on pages 2 through 15 of Statement O.

A summary of the rate base and income statement items reflecting the allocation of the projected 2010 cost of service supported by Ms. Mulkern in her testimony is provided on page 16 of Statement O.

Statement O, Schedule O-1 provides a detailed report of the projected rate base and income statement as allocated to each rate schedule. The allocation factor applied to the total North Dakota electric amount is shown on each line item.

Statement O, Schedule O-2 provides a list of the allocation factors used to allocate the total North Dakota electric amount to each class and cost component as referenced in Schedule O-1.

Q. What were the results of the embedded cost of service study?

A. The overall North Dakota electric rate of return based on the projected 2010 test period presented by Ms. Mulkern of 5.809%. The returns by customer class are as shown below:

Customer Class	ROR
Residential Service	3.386%
Small General Service	7.380%
Irrigation Service	-6.061%
General Service - Primary	5.656%
General Service – Secondary	8.602%
Time of Day Large General Service	7.621%
Space Heating Service	7.983%
Small Municipal Service	2.293%
Municipal Lighting Service – Primary	13.023%
Municipal Lighting Service – Secondary	12.394%
Municipal Pumping Service - Primary	1.276%
Municipal Pumping Service - Secondary	2.982%
Outdoor Lighting	13.744%
Interruptible Power Service	5.647%
Interruptible Demand Response Service	9.662%

Q. How did you determine what costs should be assigned to each class of customers?

A. The starting point was classifying the functionalized costs by FERC account for all rate base and income statement items as demand, energy or customer related based on the component of service being provided. Demand-related costs are costs that vary with the Kw demand imposed by the customer, energy-related costs vary with the energy or Kwh the customer uses and customer-related costs are fixed costs driven by the number of customers served.

Next the plant, expense and revenue items that were identified as directly related to a specific class of customers were directly assigned to the appropriate class. Finally, the remaining costs were allocated using the various allocation factors shown on Statement O, Schedule O-2.

Q. **Would you please provide an overview of the allocation process including the rationale underlying the choice of allocation factors?**

A. Yes. I will start with the plant in service items on the rate base schedule starting on Statement O, Schedule O-1, page 1. The plant allocation serves as the basis for allocating many of the other rate base items. The investment in production related plant items was allocated on an average and excess demand (AED) allocator to account for the contribution of each class based on a combination of the classes' average demand and non-coincident peak demands. The AED factor is comprised of the sum of the average demand of each class and the difference between the total system peak demand and the average demand as allocated to each class based on the non-coincident demand in excess of the average demand. The production investment related to the Company's wind facilities was allocated on a factor based 80% on the energy allocation factor (Factor No.1) and 20% on the AED allocator to reflect the fact the wind facilities are primarily an energy resource. The investment in transmission plant related items was allocated on the AED factor.

Turning now to the distribution plant investment; each distribution plant account is analyzed and allocated based on the cause for the investment. Station equipment and the associated land and land rights are allocated on the non-coincident peak demand of each class, representing the maximum demand on the system. The next set of plant items - Poles, Towers & Fixtures; Overhead Conductors & Devices; and Underground Conduit & Devices were classified as customer and demand related based on an analysis of the minimum and normal system design for a typical distribution system, with the minimum system representing the percentage of the plant accounts assigned to the customer component, and the remainder classified as demand related. Based on this analysis, the minimum investment necessary to connect a customer was determined to be 83% of the total required investment. The amounts classified as customer related were then allocated to each rate class based on the number of customers served in each rate class, or Factor No. 7. The dollar value of the Poles, Towers & Fixtures; Overhead Conductors & Devices; and Underground Conduit & Devices classified as demand related (17% of the total) was allocated to each rate class based on the maximum demand of each rate class (non-coincident peak Factor No. 4). The investment in Line Transformers was also classified as customer and demand related. The percentage assigned to the customer component was determined based on the minimum intercept method which seeks to identify the portion of the transformer investment associated with a hypothetical no-load condition. Based on an analysis of the type and size of transformers, representing the minimum equipment necessary to provide service to secondary system customers, the zero intercept was determined to be $1,446. Applying this amount to the number of transformers resulted in a customer component of 76% with the remaining 24% classified as demand related. The classified costs were allocated on weighted customer transformers (Factor 11) and the non-coincident secondary demand factor (Factor 5) accordingly.

The four remaining distribution accounts; Services, Meters, Installation on Customer Premises and Street Light & Signal System are all related solely to a customer connection and were classified as customer related. Services were allocated to the rate classes based on a factor representing services weighted by customer class derived by comparing the installed cost per service for each rate class to the cost necessary to serve Residential service customers. The weights were then applied to the number of customers in each rate class. The same process was used to fashion an allocation based on weighted meter costs (Factor No. 8) for allocating the embedded investment in meters. The investment in Installation on Customer Premises was directly assigned to Outdoor Lighting and the investment in Street Light & Signal Systems was directly assigned to Municipal Lighting. The allocation of the remainder of the rate base items is self explanatory with the allocation factor noted for each line item.

Q. Would you please continue with an explanation of the income statement items in the class cost of service study?

A. Yes. The allocation of the income statement items starts on Statement O, Schedule O-1, page 3 with the allocation of revenues. As shown, revenues are primarily directly assigned based on the revenues produced under each rate schedule. The revenues identified as Contracts represent the revenues produced under two specific electric service contracts. The contract revenues were allocated to each class based on demand, energy and customer allocators to offset costs associated with providing service to the two contract customers that were allocated to all other classes. The revenues to be collected under the contracts are established pursuant to the terms of the service agreements so costs were not allocated to a separate class for contracts and the billing units for customers under the contracts were not included as part of the allocation factors. The Other Revenues that cannot be directly assigned to a particular rate class are allocated based on the source of the revenue item. Each item is shown along with the allocation factor applied.

Operation and maintenance expenses consisting of fuel, purchased power costs, transmission, distribution and administrative and general expenses are shown starting at Schedule O-1, page 5. The production expenses are classified as demand and energy related with the fuel, purchased power and variable production expenses classified as energy and allocated based on the energy requirements of each class. The other production expenses and purchased capacity costs are classified as demand costs and allocated on the same demand allocator used to allocate production plant costs. Transmission operation and maintenance costs are also classified as demand related and allocated on the AED demand allocator (Factor No. 2). Customer Accounts Expense and Customer Service and Information Expenses were allocated on a weighted customer factor (Factor No. 12) based on the estimated cost of meter reading and customer billing for each class relative to the residential weighting set equal to 1.0. The remaining operation and maintenance expenses are allocated based on cost causation and typically follow the plant investment previously described in the rate base section. The remainder of the income statement reflects the allocation of depreciation expense, taxes other than income and income taxes as denoted by each line item.

Q. For what purpose has the embedded class cost of service study been used?

A. The study results have been used for the purpose of analyzing the various components comprising the total rate applicable to each customer class. In addition to providing the rate of return provided by each customer class, the class study provides the basis for the customer related costs to be collected under the Basic Service Charge component of each rate schedule and the demand related costs to be collected under the Demand Charge component of those rate schedules where demand is metered and measured for billing purposes.

Q. Would you please explain how the proposed rate increase was apportioned among the customer classes?

A. Yes. In designing the proposed rates to reflect the additional revenue requirement I first considered the results of the embedded cost study, which provided the increase required from each class to produce the overall rate of return of 9.091% as shown on the Cost by Component report provided in Statement O, pages 1 through 15 and as summarized on Statement P, page 2. While moving each rate class to the overall rate of return is a desired outcome in meeting the widely held objective of the fair return standard, the magnitude of the increases required for the residential service, irrigation service, small municipal service and municipal pumping service customers was too severe when considering the increases would be two or more times greater than the overall increase of 13.9%. It was determined that mitigation was necessary in order to balance the fair return standard with the recognition of customer impacts. The result was an equal allocation of the non-fuel related costs to each rate schedule. As Ms. Mulkern described, the Company is proposing to separate the base fuel and purchased power component between primary and secondary service which resulted in a reallocation of fuel related costs among the various primary and secondary service schedules. The allocation of the revenue increase is shown on Statement P, page 3.

Q. What is the proposed increase by class of customer?

A. As shown on Exhibit No. ___(TAA-1) and the table below, the resulting proposed percentage increase to each of the classes is as follows:

Customer Class	Revenue Increase $	Revenue Increase %
Residential Service	$6,469,473	14.1%
Small General Service	1,275,437	14.8%
General Service	7,172,206	13.6%
Municipal Lighting	195,437	13.8%
Municipal Pumping	211,142	12.4%
Outdoor Lighting Service	72,608	14.7%
Total North Dakota Electric	$15,396,303	13.9%

Q. **Once you allocated the increase in revenue to each of the customer classes, how did you then determine each of the components of the proposed rates?**

A. The embedded cost study was used as a guide in determining the level of the cost components for each rate schedule. Changes in the Base Rate and Demand Charge components have been proposed for each applicable rate schedule in order to continue to move these charges closer to cost.

Q. Would you please describe the changes you are proposing for each rate schedule?

A. Yes. Starting with Residential Service Rate 10, the base rate component (which has been renamed Basic Service Charge) was increased to $0.35 per day or $10.64 per month, an increase of $5.14 per month from the present rate. This proposed charge is well below the customer component supported in the embedded class study of $16.40 as shown on Statement O, page 1. The proposed charge provides a balance between reflecting true cost and recognizing customer impacts. The Basic Service Charge is proposed to be collected on a daily basis in order to avoid prorating the monthly charge when customers are in service less than 30 days, on average, or when a billing period extends beyond a 30 day average. The Company's natural gas service Basic Service Charge has been assessed on a daily basis since 2002 and has been well accepted by customers. The energy charges for the residential schedule were determined by reducing the total revenue responsibility for the class by the revenues to be collected under the proposed Basic Service Charge and the projected Base Fuel and Purchased Power component for secondary service. The revenues remaining to be collected were divided by the projected Rate 10 sales to determine the cost per Kwh required to be collected through the energy component. The calculations just described are provided for each rate schedule on pages 4-21 of Statement P.

The process described above for the calculation of the proposed Residential Rate 10 schedule was used to determine the rate components for each of the other rate schedules, that is, the first step was to establish the Basic Service Charge by considering the customer costs identified in the embedded cost of service study and the Demand Charge based on the demand costs identified in the embedded class cost of service study for those rate schedules where demand metering is warranted. The second step was to deduct the revenues to be recovered under the Basic Service Charge, Demand Charge and Base Fuel and Purchased Power components for each rate schedule. The Energy Charge component was then determined by dividing the revenues remaining to be collected by the projected sales under the applicable rate schedule.

A summary of the rate charges for each schedule provided on page 3 of Statement P. Exhibit No.___(TAA-2) provides the distribution of customers falling into the various annual bill impact ranges by dollar and percentage change from current bills for the residential and small general service classes.

Q. Would you please describe the new rate offering entitled Optional Residential Electric Thermal Energy Storage Rate 13?

A. Yes. As noted in the title this is an optional rate available to residential service customers with electric space heating requirements choosing to utilize a thermal storage system that uses electricity during the off-peak hours of 11:00 p.m. to 7:00 a.m. and stores that energy for use during the remaining hours of the day. This technology provides for an overall decrease in energy use of approximately 40% and the use of that energy during the time when the electric system is at its lowest use and lowest cost to serve. The rate has been established with a reduction of $.005 per Kwh from the rate applicable under Residential Service Rate 10 for use over 750 Kwh per month during the months of October through May. This rate, along with potential funds for rebates to offset upfront equipment costs, through the North Dakota Utility Rebate Program funded by The American Recovery and Reinvestment Act, will provide a cost effective conservation alternative available to residential customers.

Q. Ms. Aberle, would you please explain the Adjustment Clauses referenced on each of the proposed rate schedules?

A. Yes. The electric service rate schedules each call for the application of four separate adjustment mechanisms. The Adjustment Clauses include:

- **Load Management Tracking Adjustment (LMTA)** defined as Rate Schedule 54 is proposed in order to establish the framework for cost recovery of demand-side management and conservation program as approved by the Commission. This adjustment mechanism was originally submitted on July 1, 2009 in compliance with the Commission's Order issued in the Big Stone II prudency matter (Case No. PU-06-482) in which a Commission decision has not yet been rendered. A cost adjustment to be applicable under the mechanism is not being proposed at this time.

- **Renewable Resource Cost Recovery Rider (RRC)** defined as Rate Schedule 55, is proposed to recover the costs associated with the Company's investment in renewable resources as authorized by the Commission. This tariff was first submitted on May 29, 2009 in a filing docketed by the Commission as Case No. PU-09-225. The Company subsequently withdrew its request in Case No. PU-09-225 on November 9, 2009, noting the tariff would be filed as part of the next general rate case. The renewable resources included as part of the projected cost of service in this rate case would not be part of the RRC. The tariff is proposed herein to provide for the recovery of any future investments that are subsequently approved by the Commission outside of a general rate case.
- **Transmission Cost Recovery Rider (TCRR)** defined as Rate Schedule 56 is proposed to recover transmission investments and federally regulated transmission related costs charged to the Company that are not part of rates established in this rate case as provided for by the North Dakota Century Code at Section 49-05-04.3. As with the LMTA and the RRC, the request here is to establish the mechanisms for future use in recovering applicable expenditures and an adjustment is not proposed to be charged at this time.

- **Fuel and Purchased Power Adjustment (FPPA)** defined as Rate 58 is the mechanism currently established to recover the cost of fuel and purchased power. The adjustment mechanism has been revised as described by Ms. Mulkern to include the recovery of purchased power demand costs and to provide a means of sharing wholesale sales margins with customers which allows the Company to delete the current Margin Sharing Adjustment Rate Schedule Rate 57.

Q. Would you please briefly describe other changes made to the Company's electric tariff?

A. Yes. Following is a description of other changes the Company is proposing to make to its electric tariff as clearly identified in the legislative copy of the tariffs provided in Appendix B of the Application:

- As noted above, the Base Rate has been renamed Basic Service Charge and is stated as a daily charge for service under Rate Schedules 10, 13, 16, 20, 25, 26 and 40.
- The determination of the rate applicable to general service customers has been revised to remove the criteria associated with service entrances as this has been found to be unnecessary given the usage limits established in the last rate case.
- A new schedule entitled General Provisions Rate 100 is

proposed to provide a single point of reference for customer service related conditions and charges currently stated separated on the following schedules:

- Rule Governing Discontinuance of Service for Nonpayment of Bill -- Rate 101,
- Residential Electric Service for Permanent Employees Rate -- Rate 102,
- Consumer Deposits – Rate 106,
- Notice to Discontinue Electric Service – Rate 107,
- Reconnection Fee for Seasonal Customers – Rate 108,
- Late Payment Charge/Returned Check Charge – Rate 109,
- Method for Computing Initial or Final Bills for Electric Service for Less Than a Full Monthly Billing Period – Rate 113,
- Rules for Application of Service – Rate 114,
- Tax Clause – Rate 130,
- Selective Plan for Watthour Meters – Rate 131 and
- Rules and Policies for Implementing Master Metering Restriction – Rae 133.

- Minor changes which are self explanatory have been made to several rate schedules. These changes are clearly denoted on the tariff sheets reflecting the legislative format.

Q. Have changes been made to the provisions that you just described as moving to the new General Provisions Rate 100 schedule?

A. I am proposing to increase the returned check charge to $15.00 per occurrence to more closely track the cost of processing a return check charge. The other changes proposed were made to provide consistency with the Company's Natural Gas General Provisions Rate 100 where applicable and to provide a tariff reference to Commission Rules where appropriate, such as describing the Commission requirements relating to billing adjustments. The new Rate 100 will provide customers and employees with a ready reference to the customer service rules.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-008 Regarding: Cost of Service
Witness: Cardwell

Please provide all studies and other workpapers supporting the development of the allocation factors for the embedded class cost of service study.

Response:

Please see Statement Workpapers, Statement L pages L-1 through L-6 for a description of each allocation factor and the workpaper cross reference index. Also please see the file named "Statement L" in response to PSC – 001 data request.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
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LCG-009 Regarding: Cost of Service
Witness: Cardwell

If not provided in the previous request, please provide the load research studies supporting the development of the values in Column E, "Load Factor (%)" of the tab "demand and energy-AED" of the spreadsheet "Statement L.xlsm". Include any electronic files supporting the development of the load factors by rate class.

Response:

Please see the File LCG-009 – Load Factors in the enclosed CD.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
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LCG-010 Regarding: Cost of Service
Witness: Cardwell

Please provide, for each rate class included in the class cost of service study, the 12 class coincident peak for each month of the test year, along with all supporting load research studies/data and electronic files and workpapers. Please provide these 12 CP demands at both the meter level and the supply level for each rate class. To the extent that there are multiple metered voltages within a rate class, please provide the requested information by service voltage and rate class.

Response:

Please see Response No. MCC-090.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
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LCG-011 Regarding: Cost of Service
Witness: Cardwell

Please provide the kWh by rate class on a monthly basis for the test year, for both the Per Books and Pro Forma basis.

Response:

Please see the response to MCC – 007 Attachment A for the monthly 2014 Per Books Kwh. Also see Statement H, Page 5 and MCC-001 Attachment A for the development of the Pro Forma Kwh.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
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LCG-012 Regarding: Cost of Service
Witness: Cardwell

Please provide all studies and other workpapers supporting the demand and energy loss factors used in developing the allocation factors for the embedded class cost of service study.

Response:

Please see Response No. LCG – 012 Attachment A.

MONTANA-DAKOTA UTILITIES CO.
MONTANA ELECTRIC CASE 2015
LOSS FACTOR CALCULATION

	Energy		Demand	
	Loss Factor	Service Level Total	Loss Factor	Service Level Total
Production and Transmission	5.88%	5.88%	8.18%	8.18%
Substation Transformer Losses	0.38%	6.26%	0.47%	8.65%
Primary Lines	0.66%	6.92%	2.01%	10.66%
Distribution Transformer Losses	0.59%	7.51%	1.52%	12.18%
Service Drop	0.23%	7.74%	0.80%	12.98%
	7.74%		12.98%	

MONTANA-DAKOTA UTILITIES CO.
MONTANA ELECTRIC CASE 2015
LOSS FACTOR CALCULATION

Integrated System

Energy Loss Calculation

Year	Energy Requirements	Total Sales	System Annual Losses
2010	2,718,192	2,467,186	10.174
2011	2,776,082	2,615,677	6.132
2012	2,919,752	2,674,196	9.182
2013	3,115,064	2,847,714	9.388
2014	3,250,683	3,031,849	7.218
Total	14,779,773	13,636,622	

5-Yr Average Energy Loss Percentage:	8.38% (% of sales)	7.74% (% of total requirements)

Peak Loss Calculation

	2010	2011	2012	2013	2014
Peak Load (MW)	502.5	535.8	573.6	559.7	582.1
Annual Requirements (MWh)	2,718,192	2,776,082	2,919,752	3,115,064	3,250,683
Hours	8760	8760	8784	8760	8760
System Energy Losses %	10.174%	6.132%	9.182%	9.388%	7.218%
Xfmr No-Load Losses (MW) */	6.611	6.611	6.611	6.838	7.168
Losses on Peak	15.661%	9.515%	15.009%	14.075%	10.622%
					Avg
					12.98%

MONTANA-DAKOTA UTILITIES CO.
MONTANA ELECTRIC CASE 2015
LOSS FACTOR CALCULATION

SUMMARY OF LOSSES ON THE DISTRIBUTION SYSTEM

	Average Losses	Peak Losses
Substation Transformers Losses	0.38%	0.47%
Distribution Primary Lines	0.66%	2.01%
Distribution Transformers	0.59%	1.52%
Service Lines	0.23%	0.80%
TOTAL DISTRIBUTION LOSSES	**1.86%**	**4.80%**

Comments:

Losses were calculated by dividing the equipment losses by input energy.

Input energy is defined as the kWh consumption that enter the lines or transformers.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
DATA REQUEST
DATED SEPTEMBER 16, 2015
DOCKET NO. D2015.6.51

LCG-013 Regarding: Cost of Service
Witness: Cardwell

Please provide all supporting calculations, workpapers, and other documents for the Capacity Credit percentages used in developing Factor 3 for the embedded class cost of service study.

Response:

Please see the tab labeled "Factor 3 Wind" in the file named "Statement L" in the response to PSC – 001 for the calculation of the Capacity Credit.

The wind capacity credit for Montana-Dakota's wind facilities comes from the yearly MISO Effective Load Carrying Capabilities (ELCC) study. MISO calculates a wind penetration level (11.8%) each year based on the previous year's nameplate capacity of wind (13,403 MW) and the amount of load at previous year's peak (113,507 MW) in MISO. Then ELCC values are calculated at 10, 20, and 30 GW of wind in MISO based on the historical MISO load to generate a table of ELCC vs. wind penetration. From the table, the average of the historical ELCC data at the most recent wind penetration level is used to determine the system wide wind capacity value of 14.7%. This gives an ELCC value of 1,966 MW to spread among all of MISO's wind farms, which is calculated by taking the nameplate capacity (13,403 MW) times the wind capacity value (14.7%). Next MISO takes the average of all the wind farms output at their historical 8 summer peaks and sums those averages of each wind farm to get a total of 2,891 MW. The ELCC value (1966 MW) is then divided by the total wind (2891 MW) that was available during the historical dates to develop a coefficient (K=0.68) to calculate each wind facility's wind capacity credit. MISO then averages the historical percentages for each wind facility, and multiples that average by K to give the capacity credit for each wind facility.

Example:
Diamond Willow – 30 MW
Historical percentage = 27.067%
K = 0.68
Capacity Credit = .27067 * .68 = 18.4%

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MONTANA LARGE CUSTOMER GROUP
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LCG-014 Regarding: Cost of Service
Witness: Cardwell

Please reconcile the statement from the testimony of Sara J. Cardwell, page 5, lines 1 through 5 that the wind facilities allocation factor is weighted "20% on the AED allocator" with the calculation of Factor 3 in "Statement L.xlsm", tab "Allocation Factors" which uses a weight of 16.5%.

Response:

Page 5, Line 3 of Ms. Cardwell's testimony should read – "factor based 83.5 percent on the energy allocation factor (Factor No.1) and..."

Page 5, Line 4 of Ms. Cardwell's testimony should read – "16.5 percent on the AED allocator to reflect the fact the wind facilities are..."

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MONTANA LARGE CUSTOMER GROUP
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LCG-015 **Regarding: Cost of Service**
Witness: Cardwell

Please provide citations to any Montana PSC orders which support the Company's methodology for the allocation of wind facilities.

Response:

Recent Commission orders in Montana-Dakota's electric rate cases have not specifically addressed the allocation of wind facilities in an embedded class cost of service study.

MONTANA-DAKOTA UTILITIES CO.
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LCG-016 Regarding: Cost of Service
Witness: Cardwell

Please provide citations to any Montana PSC orders or other documents relied upon by the Company to support the methodologies of either the embedded and marginal cost of service studies.

Response:

The marginal cost study was generally prepared in general accordance with the Montana Public Service Commission's rules (ARM 38.5.176).