DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA
*****

IN THE MATTER OF THE APPLICATION OF MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc., for Authority to Establish Increased Rates for Electric Service in the State of Montana	)))))	REGULATORY DIVISION DOCKET NO. D2015.6.51

DIRECT TESTIMONY AND EXHIBITS

OF

KEVIN C. HIGGINS

ON BEHALF OF THE

MONTANA LARGE CUSTOMER GROUP

November 20, 2015

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin C. Higgins. My business address is 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a Principal in the firm of Energy Strategies, LLC. My testimony is being sponsored by the Montana Large Customer Group ("LCG").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY ENERGY STRATEGIES?

A. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MONTANA PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I testified in the Montana-Dakota Utilities Co. ("MDU") 2007 general rate case proceeding, Docket No. D2007.7.79.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE ANY OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified in approximately 200 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, North Carolina, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission.

I. <u>INTRODUCTION AND SUMMARY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the appropriate revenue requirement for MDU using the test year ended December 31, 2014, adjusted for known and measurable changes. LCG's proposed revenue requirement is based on adjustments that I am recommending in combination with the adjustments recommended by LCG witness Michael Gorman concerning cost of capital. LCG witness Stephen Baron testifies regarding class cost of service and rate design issues.

My testimony also addresses MDU's proposed Environmental Cost Recovery Rider and Transmission Cost Recovery Rider. In addition, I will address MDU's proposal to reduce customers' share of incremental wholesale margins reflected in the Fuel and Purchased Power Cost Tracking Adjustment (Rate 58) from the current 90% to 85%.[1]

Q. PLEASE SUMMARIZE MDU'S REQUESTED ELECTRIC RATE INCREASE.

A. MDU has requested an electric rate increase of $11,755,752, and is proposing to effectuate this increase by applying an equal percentage increase to each customer class of 21.1%.[2]

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS REGARDING MDU'S PROPOSED REVENUE REQUIREMENT INCREASE?

A. Yes. The fact that MDU is proposing an overall rate increase of 21.1% is noteworthy considering that the Company is over-earning on a 2014 per book basis. As shown on Rule 38.5.175, MDU's actual per-books earnings in 2014 were 8.256%, considerably higher than the Company's requested return of 7.588%. If the Commission were to approve a 21.1% overall increase as proposed by MDU, the result would be an example of rate shock, which is a sudden and dramatic increase in rates. However, there is no reasonable basis for an increase of this magnitude. As I will describe below, the very large rate increase and associated rate shock proposed by MDU is largely a function of MDU's overreaching and unreasonable proposed test-year structure.

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[1] MDU has also proposed conforming changes to the treatment of wholesale sales margins for Contract Service Rate 35.

[2] Direct Testimony of Nicole A. Kivisto, p. 4, lns. 10-17.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS CONCERNING REVENUE REQUIREMENT.

A. I offer the following conclusions and recommendations:

1) The test period approach advanced by MDU is highly problematic and does not comport with good ratemaking principles. MDU has combined average-of-period 2015 post-test-year adjustments with selective end-of-period adjustments for major facilities – all layered on top of a 2014 test year, creating a patchwork of inconsistent test period measurements for determining MDU's revenue requirement.

2) I have restated MDU's end-of-period rate base for its four major plant additions in 2015 on an average-of-period basis (along with conforming changes to expense). Relative to MDU's proposed revenue requirement, this restatement reduces the Montana revenue requirement (net of increased fuel expense) by **$2,584,324** for the Big Stone – AQCS Project; by **$496,564** for the Lewis & Clark MATS Project; by **$1,279,164** for the Lewis & Clark RICE Units Project; and by **$1,855,463** for the Thunder Spirit Wind Farm Project.

3) MDU has replaced its 2014 test period transmission expense with a hybrid of projected end-of-period (*i.e.*, annualized) 2015 expenses and projected 2016 costs. I recommend an adjustment that replaces MDU's 2015/2016 hybrid approach with 2015 calendar year pro forma transmission expense as a known and measurable change. This adjustment reduces the Montana revenue requirement by **$984,337** relative to MDU's proposal.

4) MDU has determined that the Company has over-recovered decommissioning costs from Montana customers in the amount of approximately $6.7 million. MDU proposes to credit customers this amount as an offset to depreciation expense over a ten-year period, whereas I believe a five-year amortization period is more appropriate. My adjustment reduces the Montana revenue deficiency by **$673,239** relative to MDU's filed case.

5) Since filing its direct case, MDU has updated the depreciation rates for the Big Stone Plant. Recognizing the effects of these updated depreciation rates reduces the Montana revenue requirement by **$216,071**, excluding any deferred income tax impacts.

6) For ratemaking purposes, it is preferable to use a normalization technique for generation overhaul expense because the actual overhaul expense in a given test period may not be representative of annual overhaul expense over time. For the purposes of this case, I recommend that generation overhaul expense be based on the historical five-year annual average for this expense for the years 2010 through 2014. This adjustment reduces the Montana revenue deficiency by **$311,858** relative to MDU's filed case.

7) Mr. Gorman's recommended capital structure reduces the Montana revenue requirement by **$366,063** relative to MDU's filed case. His cost of debt adjustment reduces the Montana revenue requirement by **$71,657** relative to MDU's filed case and his return on equity adjustment reduces the Montana revenue requirement by **$479,265**.

8) MDU proposes to recover deferred Public Service Commission ("PSC") and Montana Consumer Counsel ("MCC") taxes from its customers over a one-year period on a per-kWh basis. I believe a three-year amortization is more appropriate, and as LCG witness Mr. Baron testifies, the deferral is more properly recovered on a uniform percentage factor applied to customer base rate revenues rather than a kWh charge. Changing the amortization period to three years will reduce the amount of this cost component by **$266,497** in the rate effective year. Because this cost component is not included in the revenue requirement increase proposed by the Company, I have not shown my adjustment as a reduction to the requested revenue requirement filed by MDU.

Q. PLEASE SUMMARIZE THE IMPACT OF LCG'S ADJUSTMENTS TO MDU'S PROPOSED REVENUE REQUIREMENT INCREASE.

A. The impacts of LCG's recommended adjustments for the test period ended December 31, 2014 are presented in Exhibit KCH-1, which has been summarized in Table KCH-1 below.

LCG's adjustments reduce MDU's Montana base revenue requirement deficiency by **$9,318,005** relative to MDU's filing. LCG's final revenue requirement recommendation is for a **$2,437,539** increase relative to current base rates. This contrasts with the increase of **$11,755,544** proposed by MDU in its direct filing.

Table KCH-1

Summary of Revenue Requirement Impact of LCG Adjustments

	Adjustment	Increase
MDU As-Filed Requested Increase		**$11,755,544**
LCG Adjustments		
Big Stone AQCS Project Adjustment	($2,584,324)	$9,171,220
Lewis & Clark MATS Project Adjustment	($496,564)	$8,674,656
Lewis & Clark - RICE Units Project Adjustment	($1,279,164)	$7,395,492
Thunder Spirit Wind Farm Adjustment	($1,855,463)	$5,540,029
Transmission Expense Adjustment	($984,337)	$4,555,692
Decommissioning Over-Recovery Amortization Adjustment	($673,239)	$3,882,453
Depreciation Update - Big Stone	($216,071)	$3,666,382
Generation Overhaul Expense Adjustment	($311,858)	$3,354,524
Capital Structure Adjustment	($366,063)	$2,988,461
Cost of Debt Adjustment	($71,657)	$2,916,804
Return on Equity Adjustment	($479,265)	$2,437,539
Total LCG Adjustments	**($9,318,005)**	
LCG Recommended Increase		**$2,437,539**

Note: The summary above does not include LCG's recommended adjustment to MDU's proposed recovery of deferred MCC and PSC Taxes.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS CONCERNING MDU'S PROPOSED NEW COST RECOVERY MECHANISMS.

A. I recommend that both the Environmental Cost Recovery Rider and the Transmission Cost Recovery Rider be rejected by the Commission. Both proposals are examples of unwarranted single-issue ratemaking.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS CONCERNING MDU'S PROPOSED CHANGES TO THE TREATMENT OF WHOLESALE SALES MARGINS.

A. MDU has proposed to reduce customers' share of incremental wholesale sales margins reflected in the Fuel and Purchased Power Cost Tracking Adjustment (Rate 58) from the current 90% to 85%, while setting the wholesale sales margins included in base rates at

$0. I believe the movement to an 85/15 sharing arrangement for wholesale sales margins is reasonable if it is also accompanied by a change in the sharing arrangement for the fuel and purchased power cost tracking adjustment to the same 85/15 split. Incentives are important for ensuring that utilities seek opportunities for wholesale sales as well as for managing their fuel costs. It is reasonable for <u>both</u> sharing bands to be moved from the current 90/10 to 85/15, but only if both are moved in tandem. It would not be reasonable to move the wholesale sales margins sharing to 85/15 while retaining a 90/10 sharing mechanism for fuel and purchased power costs.

II. TEST PERIOD

Q. WHAT TEST PERIOD IS MDU PROPOSING IN THIS CASE?

A. MDU is proposing to use a historical test period ended December 31, 2014, with numerous adjustments occurring through the pro forma period ending December 31, 2015. MDU has reflected plant additions, with the exception of its large generation project additions, using a beginning and ending average approach for calendar year 2015,[3] and also reflects a beginning and ending average of 2015 accumulated depreciation for these assets.[4] However, for its four large generation projects (the Big Stone AQCS environmental project, the Lewis & Clark MATS environmental project, the RICE Units located at Lewis & Clark Station site, and the Thunder Spirit Wind Farm), MDU is proposing an <u>end</u>-of-period approach that treats these facilities as if they were in

[3] Rule 38.5.125, Statement C, pp. 2-7.
[4] Rule 38.5.133, Statement D, p. 2.

service for the entire calendar year 2015,[5] even though none of these projects are projected to be placed into service prior to November 30, 2015.[6]

MDU has also annualized the depreciation expense associated with these four large generation projects,[7] and has reflected a full year of operations and maintenance expenses for them as well.[8] In addition, MDU has increased its labor and benefits expenses to reflect the annualized expenses for incremental Power Production Department employees that will be in place by the end of 2015.[9]

Q. WHAT IS THE PURPOSE OF A TEST PERIOD WHEN SETTING PUBLIC UTILITY RATES?

A. In Montana, electric utility rates are designed to generate revenues that will match the sum of the utility's reasonable operation and maintenance expenses, depreciation and amortization expenses, and taxes, while providing the utility an opportunity to earn a fair return on invested capital. The matching principle, which is a pervasive principle in both accounting and ratemaking, requires that customer service requirements, sales volumes, revenues, expenses, and investments all be synchronized or measured within the context of a consistent accounting or test period. Simply put, a "test period" is a consecutive twelve-month period used to measure a utility's revenue requirement and average unit cost of service. A test period typically consists of a consecutive twelve-month period to reflect seasonal variations in customer usage patterns and the Company's business cycle. A test period revenue requirement divided by test period sales volumes produces average

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[5] See the Direct Testimony of Travis R. Jacobson, p. 19.
[6] MDU's response to Data Request LCG-023, which is provided in Exhibit KCH-13.
[7] See the Direct Testimony of Travis R. Jacobson, p. 16, lns. 10-11.
[8] See *Id.*, p. 10, lns. 13-20 and MDU Statements A-O Workpapers, p. G-78.
[9] *Id.*, p. 9, lns. 15-23, through p. 10, lns. 1-2.

rates. These average rates can remain valid into future years as sales volumes change along with cost changes.

Q. WHAT IS YOUR ASSESSMENT OF THE COMPANY'S PROPOSED TEST PERIOD APPROACH?

A. The test period approach advanced by MDU is highly problematic and does not comport with good ratemaking principles because it does not match expenses, investments, and revenues in a consistent 12-month period. Before addressing these problems I note at the outset that, although MDU is nominally using a 2014 historic test period, the Company has made so many adjustments using 2015 projected plant balances and expenses that, in many respects, the 2015 post-test-year period is serving as the *de facto* test period in this case, albeit with fatal structural flaws. Based on my review of MDU's filing, it is clear that the 2015 post-test-year adjustments are driving the large proposed rate increase.

Q. WHAT IS THE MAJOR PROBLEM WITH MDU'S TEST PERIOD APPROACH IN THIS CASE?

A. The major problem is that MDU has combined average-of-period 2015 post-test-year adjustments with selective end-of-period adjustments for major facilities – all layered on top of a 2014 test year, creating a hodgepodge of inconsistent test period measurements for determining MDU's revenue requirement. In this context, MDU's proposal to treat the four major plant additions on an end-of-period basis materially overstates the rate base in place during the 2015 post-test-year pro forma period and thus causes an overstatement of the Montana revenue requirement.

MDU's test period also suffers from a second structural defect, although, as I discuss below, this defect does not result in a material impact on revenue requirement in this particular case. Specifically, although MDU proposes numerous and significant post-test-period pro forma adjustments that increase rate base and expenses, the Company made no effort to take account of incremental revenues in the 2015 pro forma period. The absence of any incremental revenues is particularly notable when, at the time the filing was made, MDU anticipated material Montana load growth and load growth is one of MDU's justifications for new plant additions. Thus, as filed, the test period approach put forward by MDU violates the important matching principle in ratemaking.

The upshot is that MDU's inconsistent test period measurements produce a proposed revenue requirement that is neither just nor reasonable and is a major cause of the rate shock that would result from adoption of the Company's request.

Q. WHAT CHANGES ARE YOU RECOMMENDING TO MDU'S PROPOSED TEST PERIOD TREATMENT?

A. My recommended changes fall into two main categories: (1) Restating MDU's end-of-period rate base for its four major plant additions in 2015 on an average-of-period basis (along with conforming changes to expense); and (2) Adjusting MDU's projection of 2015 transmission expense to reflect pro forma 2015 levels, rather than a hybrid of 2015 annualizations and 2016 projections as proposed by MDU.

I also discuss the appropriate treatment of incremental revenues when making post-test-period plant adjustments, although I am not proposing a specific adjustment to the Montana revenue deficiency for this item in this proceeding.

A. <u>Four Major Plant Additions in 2015</u>

Q. PLEASE DESCRIBE THE FOUR MAJOR PLANT ADDITIONS THAT MDU IS PROPOSING TO INCLUDE ON AN END-OF-PERIOD BASIS.

A. As I noted above, the four projects are the Big Stone Air Quality Control System ("AQCS") environmental project, the Lewis & Clark Mercury and Air Toxic Standards ("MATS") environmental project, the Reciprocating Internal Combustion Engine ("RICE") Units located at the Lewis & Clark Station site, and the Thunder Spirit Wind Farm.

Big Stone Plant is a single-unit 456 MW coal-fired plant near Big Stone City, South Dakota, of which MDU owns a 22.7% share. The ACQS project was undertaken to achieve compliance with the Regional Haze and MATS Rules, and includes selective catalytic reduction equipment, a circulating dry scrubber, a bag house, and an activated carbon injection system.[10] The AQCS project is projected to be commercially operational on December 1, 2015,[11] and MDU has proposed to include the $89.9 million Total Company ($21.8 million Montana-allocated) plant addition in its revenue requirement.

The Lewis & Clark Station is a single-unit 50 MW lignite-fired plant near Sidney, Montana.[12] The MATS compliance project includes turning vanes to change the distribution of the flue gas within the stack, a sieve tray and mist eliminator system, and a forced oxidation system.[13] The MATS project is projected to be commercially operational on November 30, 2015,[14] and MDU has proposed to include the $16.2 million

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[10] Direct Testimony of Alan L. Welte, pp. 6-7.
[11] MDU Response to Data Request LCG-023, which is provided in Exhibit KCH-13.
[12] Direct Testimony of Jay Skabo, p. 5, lns. 17-18.
[13] Direct Testimony of Alan L. Welte, p. 5, lns. 11-18.
[14] MDU Response to Data Request LCG-023, which is provided in Exhibit KCH-13.

Total Company ($3.7 million Montana-allocated) plant addition in its revenue requirement.[15]

The RICE Units consist of two 9.3 MW (18.6 MW total) natural gas-fired Wartsilla generating units co-located with the Lewis & Clark Station.[16] The RICE project will be used as a rapid start generating resource and will provide system support if transmission outages and curtailments occur in the transmission constrained areas of eastern Montana and western North Dakota.[17] The RICE Units are projected to be commercially operational on November 30, 2015,[18] and MDU has proposed to include the $43.3 million Total Company ($9.8 million Montana-allocated) plant addition in its revenue requirement.[19]

The Thunder Spirit Wind Farm is a new 107.5 MW wind project in Adams County, North Dakota,[20] with a projected commercial operations date of December 31, 2015.[21] While MDU originally planned to buy the output from Thunder Spirit through a 25-year PPA, MDU now plans to acquire the project.[22] MDU has proposed to include the $220.0 million Total Company ($56.7 million Montana-allocated) plant addition in its revenue requirement.[23]

Q. WHY DOES TREATING THE FOUR MAJOR PLANT ADDITIONS ON AN END-OF-PERIOD BASIS CAUSE AN OVERSTATEMENT OF THE MONTANA REVENUE REQUIREMENT?

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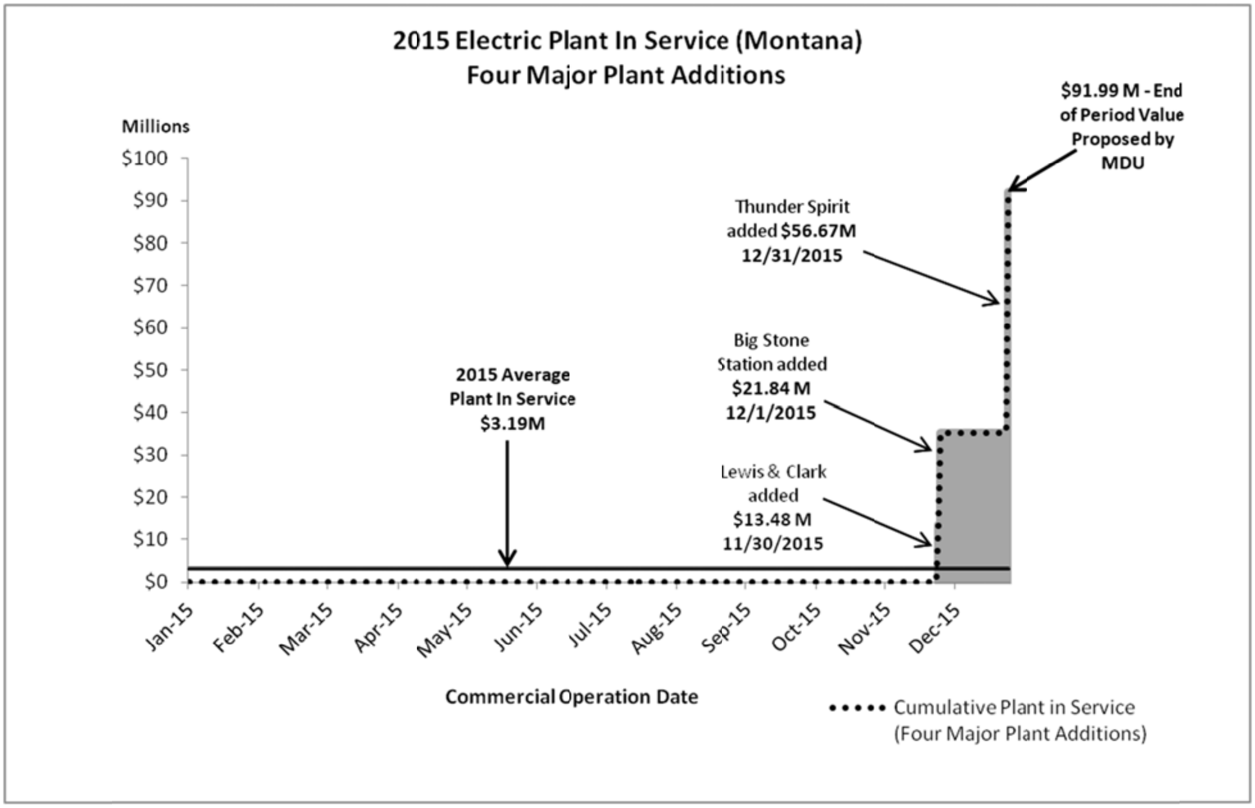
[15] Rule 38.5.125, Statement C, p. 8.
[16] Direct Testimony of Jay Skabo, p. 3, lns. 14-20.
[17] Direct Testimony of Darcy J. Neigum, p. 10, lns. 14-18.
[18] MDU Response to Data Request LCG-023, which is provided in Exhibit KCH-13.
[19] Rule 38.5.125, Statement C, p. 8.
[20] Direct Testimony of Darcy J. Neigum, p. 13, lns. 6-7.
[21] MDU Response to Data Request LCG-023, which is provided in Exhibit KCH-13.
[22] Direct Testimony of Darcy J. Neigum, pp. 15-17.
[23] Rule 38.5.125, Statement C, p. 8.

A. During the test period utilized in a rate case the utility's return is calculated as a function of its rate base. Since the value of rate base changes each month as new plant is added and existing plant depreciates, the preferred approach is to determine test period rate base by averaging each month's rate base value (*i.e.*, using an average-of-period rate base). This approach ensures that the asset base upon which the utility's return is measured is reflective of its "typical" value during the course of the test period. In contrast, end-of-period rate base, as proposed by MDU for the four major plant additions, measures the Company's (2015) return by measuring the plant-in-service at the end of 2015 while simultaneously "pretending" the major plant was in service for the entirety of 2015, thereby overstating the Company's actual investment in plant in service during the 2015 post-test-year period. By overstating its actual investment in plant in service during the 2015 post-test-year period, MDU *understates* its test period rate of return and consequently *overstates* its revenue requirement deficiency.

The relationship between the average 2015 plant-in-service for these four major plants additions and the end-of-period plant-in-service proposed by MDU is illustrated in Figure KCH-1, below.

Figure KCH-1



Q. PLEASE EXPLAIN WHAT IS SHOWN IN FIGURE KCH-1.

A. Figure KCH-1 shows the additions to electric plant-in-service during the 2015 post-test-year period for the four major plant additions. The dotted line in the figure shows the actual plant-in-service chronologically and cumulatively for the four additions, which is zero until November 30th. More than 50% of the value of the additions is projected to be added on the last day of the year, December 31st.

The December 31st peak value of $92 million is the value of electric plant that MDU proposes to include in its Montana rate base in this case. In contrast, the solid horizontal line in the figure is the average plant in service for the four plant additions during 2015, which is only $3.2 million. This latter value best represents the Company's actual investment in plant in service for the four major plant additions for the duration of 2015. Simply put, MDU is proposing to earn a return on $92 million of projected new plant when the average amount of new plant during the post-test-year period is expected to be only $3.2 million.

It is important to bear in mind that the end-of-period adjustments that MDU is proposing here are not for plant added during the nominal test year of 2014 – which is not even depicted in this figure and would lie to the left of it – but for the post-test-year period. In my opinion, MDU's proposal for end-of-period treatment for post-test-year plant is unsynchronized with the underlying test period and is overreaching.

Q. HAVE YOU REVIEWED THE COMMISSION'S ADMINISTRATIVE RULES REGARDING TEST PERIOD STRUCTURE AND ADJUSTMENTS?

A. Yes, I have.

Q. DO THE ADMINISTRATIVE RULES PROVIDE ANY GUIDANCE WITH RESPECT TO THE USE OF AVERAGE RATE BASE VERSUS END-OF-PERIOD RATE BASE?

A. Yes, Rule 38.5.125 requires that:

> Working papers shall show plant balances on a beginning and end of period basis average for the test period representing functional classifications and total plant. The effect of proposed adjustments, if any, on the average balances shall also be shown.

Although I am not an attorney, it appears to me that this language indicates that information on electric plant-in-service must be presented on an average basis, consistent with the use of average rate base in ratemaking.

Q. DO THE ADMINISTRATIVE RULES ALLOW FOR THE USE OF END-OF-PERIOD RATE BASE?

A. Yes. Rule 38.5.606 provides for an *optional* filing procedure that includes an end-of-period rate base provision.[24] However, MDU has not filed its case pursuant to this optional filing standard, citing instead to Rule 38.5.101, et seq. [25] Indeed, the optional filing standard contains certain requirements that are completely absent from MDU's filing, such as updating test year revenues to reflect end-of-period customer counts, annualization of known changes in revenues occurring during the test year, and other known and measurable changes to revenues occurring prior to the Commission's hearing on the utility's rate application (up to 13 months beyond the test period). [26] It is clear to me that MDU has not filed its case pursuant to the optional filing standard.

Q. WHAT ADJUSTMENTS ARE YOU RECOMMENDING TO ADDRESS MDU'S USE OF END-OF-PERIOD RATE BASE FOR ITS FOUR MAJOR PLANT ADDITIONS?

A. Although strict adherence to a 2014 historical test period could reasonably call for exclusion of these investments from the revenue requirement determination altogether, I am recommending that the four major plant additions be included in rate base at 2015 average rate base levels as known and measurable changes. This would allow MDU to earn a return on these investments in proportion to the period of time during calendar year 2015 that these facilities were actually in service (or are projected to be in service). I calculated average rate base for these four plant additions using a 13-month average rate base for the year based on the projected in-service date for each plant, as identified in

[24] 38.5.606(d).
[25] See MDU Application, p. 1.
[26] 38.5.606(e).

discovery responses provided by MDU.[27] In calculating the 13-month average rate base I also took account of those instances in which major new additions are projected to come on line at the end of a month by pro-rating the average rate base in the initial month for portion of the month that the plant is anticipated to be in service.

In addition to adjusting rate base to average-of-period levels, I am including conforming adjustments to expense to reflect 2015 pro forma levels (rather than year-end levels) to reflect and match the level of expense activity actually anticipated for calendar year 2015 for these plants. This includes a significant *upward* adjustment for fuel expense, as MDU calculated test period fuel expense by assuming that the Thunder Spirit Wind Farm was operational (and therefore displaced fuel costs) for all of 2015 when in fact the facility is not projected to come on line until the very last day of the year, December 31st.

Q. WHY DID YOU USE A 13-MONTH AVERAGE TO CALCULATE AVERAGE RATE BASE FOR THE 2015 MAJOR PLANT ADDITIONS RATHER THAN A BEGINNING-OF-PERIOD / END-OF-PERIOD AVERAGE?

A. The 13-month average rate base is appropriate firstly because it provides much greater precision, particularly since I prorate the portion of the initial month that the plant is in service, and secondly because my use of it is essential to properly match the calculation of the conforming expense adjustments, which are also tied to the specific dates that the new plant is expected to come into service. For example, the Thunder Spirit Wind Farm is not expected to come on line until the last day of 2015. Thus, the displacement of fuel and purchased power by this wind facility is theoretically expected to occur on only one

[27] See MDU Response to Data Request LCG-023, which is provided in Exhibit KCH-13.

day in 2015, *i.e.*, December 31st (although in discovery MDU indicated that the output of this plant would actually be zero during 2015).[28] Consequently, my adjustment for fuel and purchased power adds back in the fuel and purchased power expense that MDU had removed for the entirety of 2015. As my conforming adjustment adds back in fuel and purchased power expense for the full year, it is necessary that the Thunder Spirit rate base addition match that treatment and not be included in rate base for any more than one day in 2015.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR ADJUSTMENTS FOR THE FOUR MAJOR PLANT ADDITIONS?

A. I present separate adjustments for each of the four new facilities.

My adjustment for the Big Stone – AQCS Project is presented in Exhibit KCH-2. I estimate that this adjustment reduces Montana revenue requirement by **$2,584,324** relative to MDU's proposal.

My adjustment for the Lewis & Clark MATS Project is presented in Exhibit KCH-3. I estimate that this adjustment reduces the Montana revenue requirement by **$496,564** relative to MDU's proposal.

My adjustment for the Lewis & Clark RICE Units Project is presented in Exhibit KCH-4. I estimate that this adjustment reduces the Montana revenue requirement by **$1,279,164** relative to MDU's proposal.

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[28] See MDU Response to Data Request LCG-025, which is provided in Exhibit KCH-13.

And my adjustment for the Thunder Spirit Wind Farm is presented in Exhibit KCH-5. I estimate that this adjustment reduces the Montana revenue requirement by **$1,855,463** relative to MDU's proposal.

Finally, I note that while my adjustments regarding the four major plant additions reduce Montana's revenue requirement relative to MDU's proposal, my proposed treatment of these four items still results in a material increase in Montana revenue requirement relative to 2014 per-books revenues of approximately $1.8 million.[29]

B. <u>Transmission Expense</u>

Q. HOW HAS MDU TREATED TRANSMISSION EXPENSE IN THE CONTEXT OF ITS TEST PERIOD?

A. MDU has replaced its 2014 test period transmission expense with a hybrid of projected end-of-period (*i.e.*, annualized) 2015 expenses and projected 2016 costs. While there is no clear-cut way to categorize the Company's test period treatment of transmission expense, it most closely resembles a projected 2016 test period.

Q. WHAT EXPLANATION DOES MDU OFFER FOR ITS TREATMENT OF TRANSMISSION EXPENSE?

A. MDU witnesses Travis R. Jacobson notes that a transmission agreement between MDU and Basin Electric Power Cooperative ("BEPC") is scheduled to expire in 2015.[30] The expiration will occur at midnight on December 31.[31] Mr. Jacobson removes these expenses from the test period in MDU's Adjustment 11. In Adjustment 12, Mr. Jacobson

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[29] In MDU's Response to PSC-071, Attachment A, the Company shows a proposed total revenue requirement increase associated with the four additions of approximately $8.0 million, whereas my recommended adjustments reduce this by approximately $6.2 million.
[30] See the Direct Testimony of Travis R. Jacobson, p. 10.
[31] MDU Response to Data Request LCG-046(a), which is provided in Exhibit KCH-13.

reflects the cost of replacing this expired agreement plus various other increased transmission costs. These other increased transmission costs include: (1) incremental network transmission service from Southwest Power Pool ("SPP") to replace incremental network transmission service from Western Area Power Administration ("WAPA") that expired on September 30, 2015;[32] (2) an increase in charges for replacing a transmission service agreement with WAPA that will expire December 31, 2015 with network integrated transmission service from SPP;[33] and (3) increased 2015 transmission charges from the Midwest Independent System Operator ("MISO").[34]

Q. WHAT IS YOUR ASSESSMENT OF MDU'S APPROACH TO REFLECTING TEST PERIOD TRANSMISSION EXPENSE?

A. Consistent with my assessment of the treatment of the four major plant additions, I do not object to reflecting calendar year 2015 pro forma expenses as known and measurable adjustments to the 2014 test period. However, MDU's proposed test year treatment is considerably more aggressive in that it includes replacing 2015 actual expenses using the projected cost of replacement services in 2016. Cases in point include the replacement of the BEPC and WAPA transmission service agreements, each of which will expire at midnight on December 31, 2015. Strictly speaking neither of these contracts expires *during* 2015 but rather immediately at the end of the year. This distinction is not a mere technicality but an illustration of the fact that MDU is effectively attempting to adjust its 2014 test period transmission expense with projected 2016 costs. In my opinion, this approach is overreaching and constitutes an unreasonable test period mismatch.

[32] MDU Response to Data Request LCG-046(b), which is provided in Exhibit KCH-13.
[33] Direct testimony of Darcy J. Neigum, pp. 33-34; MDU Response to Data Request LCG-046(e).
[34] Direct testimony of Darcy J. Neigum, p. 39; MDU Response to Data Requests LCG-046(f) & (g).

Q. WHAT IS YOUR RECOMMENDED TEST PERIOD TREATMENT OF TRANSMISSION EXPENSE?

A. I recommend an adjustment that replaces MDU's 2015/2016 hybrid approach with 2015 calendar year pro forma transmission expense as a known and measurable change that is fully synchronized with my recommended treatment of the four major plant additions discussed above as well as other 2015 pro forma adjustments proposed by MDU.

This adjustment is presented in Exhibit KCH-6. I estimate that this adjustment reduces the Montana revenue requirement by **$984,337** relative to MDU's proposal. I note, however, that while my adjustment reduces the Montana revenue requirement relative to MDU's proposal, it still represents an increase of **$169,253** relative to 2014 per-books expense for the Montana jurisdiction.[35]

C. 2015 Pro Forma Revenues

Q. WHY DO YOU BELIEVE THAT AN ADJUSTMENT FOR PRO FORMA REVENUES IS GENERALLY APPROPRIATE WHEN MAKING POST-TEST-PERIOD ADJUSTMENTS?

A. In general, an adjustment to account for pro-forma revenues is appropriate when making post-test-period adjustments of the sort that MDU has proposed. Accounting for growth in pro-forma revenues is necessary to conform to the matching principle in ratemaking. It is particularly important to adhere to the matching principle when post-test-period adjustments are being proposed for investment in new plant that the utility is justifying on the grounds of meeting load growth.

Q. DOES MDU'S FILING INCLUDE AN ADJUSTMENT TO ACCOUNT FOR 2015 PRO FORMA REVENUES?

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[35] Derived from Exhibit KCH-6, p. 2.

A. No.

Q. ARE YOU PROPOSING AN ADJUSTMENT FOR 2015 PRO FORMA REVENUES IN THIS PROCEEDING?

A. No, I am not. But that is only because the most recent information regarding MDU's actual 2015 sales and revenues indicates that such an adjustment is not warranted in this case on factual grounds. In contrast, it appears that MDU elected not to consider a revenue adjustment for load growth even when it was anticipated that load growth would be material. I disagree with MDU's approach to this issue as a matter of principle and I believe that some discussion on the matter is warranted to ensure that the violation of the matching principle is not repeated in a future MDU rate proceeding.

Q. PLEASE CONTINUE. HOW IS MDU'S CURRENT FILING INCONSISTENT WITH THE MATCHING PRINCIPLE?

A. As I discussed above, MDU incorporates adjustments for both calendar year 2015 rate base and, in the case of the four major plant additions, end-of-period 2015 rate base (which resembles 2016 average rate base). In addition, MDU includes numerous expense adjustments that reflect both calendar year 2015 pro forma expenses and annualized (or end-of-period) 2015 expenses (some of which are more akin to beginning-of-period 2016 expenses). While I have objected to the more aggressive proposals by MDU to use end-of-period 2015 values, I have not objected to reflecting calendar year 2015 pro forma rate base and expenses in the test period revenue requirement as known and measurable changes.

Noticeably absent from MDU's proposal is any reflection of increased revenues from 2015 load growth in Montana, despite the fact that at the time the filing was made, MDU was anticipating material Montana load growth.[36] Thus, by *including* rate base and expense adjustments for 2015 plant additions and expense, while *excluding* 2015 revenue growth, the test period approach put forward by MDU violates the important matching principle in ratemaking. It is particularly problematic to be excluding 2015 revenue growth while proposing a 21.1% rate increase that is driven, in significant part, by 2015 plant additions that the Company justifies, in part, as a way to meet its growing service territory load.[37]

Q. HAS MDU PROVIDED ANY EXPLANATION FOR ITS EXCLUSION OF 2015 REVENUE GROWTH?

A. MDU does not provide an explanation in the Company's direct testimony, but provides insight into its rationale in its discovery responses. In particular, in its response to LCG-033(b), in which MDU was asked to explain why the Montana load growth projected for 2015 in the Company's IRP (or any more recent forecast) was not incorporated into the rate case filing, MDU's reply is that "The Company did not use the 2015 forecasted sales volumes from the IRP in accordance with ARM 38.5.106."

Q. HAVE YOU REVIEWED ARM 38.5.106?

A. Yes, I have.

Q. DO YOU UNDERSTAND MDU'S RESPONSE IN LIGHT OF YOUR REVIEW?

A. No. ARM 38.5.106 states, in its entirety:

[36] MDU's 2015 IRP projected 4.7% load growth for Montana in 2015 and subsequent updates to the Company's forecast provided during the pendency of this proceeding continued to show load growth, albeit at a reduced level. See MDU's Responses to Data Requests PSC-022 Attachment A, LCG-032 Attachment A, and LCG-033 Attachment A.

[37] See direct testimony of Darcy J. Neigum, pp. 10 and 17-18.

38.5.106 ANALYSIS OF SYSTEM COSTS FOR A TWELVE MONTH HISTORICAL TEST YEAR

(1) The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months actual experience ending no earlier than 9 months prior to the date of filing of the data required by ARM 38.5.101 and 38.5.105, unless good cause be shown. This analysis shall include the return, taxes, depreciation, and operating expenses, and an allocation of such costs to the services rendered. The information submitted with the statement shall show the data itemized below for the test period, as reflected on the books of the filing public utility. Any proposed adjustments to book costs shall be explained in writing. Such adjustments shall be shown separately and shall be fully supported, including schedules showing their derivation, where appropriate. However, no adjustments shall be permitted unless based on changes in facilities, operations, or costs which are known with certainty and measurable with reasonable accuracy at the time of the filing. No adjustment will be entertained unless it will become effective within 12 months of the last month of the test period as used in this section.

MDU is apparently interpreting this rule as requiring a prohibition on revenue adjustments when a rate case is filed using an historical test period. As I am not an attorney I cannot provide a legal interpretation of this rule. However, I note that the word “revenue” is never used in the rule. I assume that MDU is relying on the passage that states that “no adjustments shall be permitted unless based on changes in facilities, operations, or costs which are known with certainty and measurable with reasonable accuracy at the time of the filing.” However, I note that the title of this rule is “Analysis of system *costs* for a twelve month historical test year,” so it is not surprising to me that the limitation on adjustments to those which are known and measurable calls out only cost-related items (facilities, operations, or costs) as distinct from revenues.

Q. FROM A POLICY PERSPECTIVE DOES IT MAKE SENSE TO PERMIT ADJUSTMENTS FOR POST-TEST-PERIOD FACILITIES, OPERATIONS, OR COSTS, BUT TO PROHIBIT ADJUSTMENTS FOR POST-TEST-PERIOD REVENUE GROWTH?

A. No, such a prohibition would make no sense at all, which is why I believe that MDU's interpretation must be incorrect. Such a prohibition would obviously violate the matching principle, which is recognized elsewhere in the Commission's administrative rules. To allow adjustments for new facilities, for example, but not to recognize the revenues from load growth that caused new facilities to be constructed in the first place, is simply wrong.

Q. GIVEN THE FOREGOING DISCUSSION, WHY ARE YOU NOT RECOMMENDING AN ADJUSTMENT TO INCORPORATE REVENUES FROM MONTANA LOAD GROWTH?

A. Had Montana load growth materialized at the levels projected by MDU in its IRP or subsequent load forecasts, then I would be recommending such an adjustment. However, prior to preparing such an adjustment, I reviewed the Company's most recent Montana sales information, covering the 12-month period of actual sales from October 2014 through September 2015. This most recent sales information indicates that the Company's load growth has not materialized to the levels previously anticipated. Based on this review I have determined that as a *factual* matter, a load growth adjustment to revenue is not warranted in this proceeding. Although my recommendation and MDU's approach produce the same result with respect to incremental revenues from load growth, this convergence of result is a matter of happenstance. In my case, I am not making this adjustment because the facts in this proceeding do not support it. In MDU's case, a load growth adjustment is not made apparently as a matter of general practice. The former decision is supportable, whereas the Company's apparent general practice is not, in my opinion. If, in future rate proceedings, MDU proposes material post-test-period adjustments, then post-test-period revenue growth should also be considered in determining any revenue deficiency or sufficiency, if it can be supported by the facts in the case.

III. AMORTIZATION OF DECOMMISSIONING OVER-RECOVERY

Q. WHAT IS DECOMMISSIONING OVER-RECOVERY?

A. Current depreciation rates include a component that is intended to recover over time the cost of decommissioning certain power generation facilities. As reported by Mr. Jacobson, MDU has undertaken studies to support the cost to decommission its existing production fleet and has determined that the portion allocated to Montana is less than the accumulative balance recovered from ratepayers as of December 31, 2014. This means that MDU already over-recovered this cost from its Montana customers through their past contributions in rates. The over-recovery is approximately $6.7 million.[38] In light of this information, MDU is proposing to discontinue the collection of decommissioning costs for its existing power production facilities and is proposing to amortize, or return to customers, the over-recovered balance over ten years. This approach would result in a decrease in depreciation expense of $671,219 annually.[39]

Q. WHAT IS YOUR ASSESSMENT OF MDU'S PROPOSAL TO AMORTIZE THE OVER-RECOVERY OF DECOMMISSIONING COSTS?

A. In general, it is appropriate to return this over-recovery to customers by means of an offset against depreciation expense, as proposed by MDU. However, I believe the amortization period proposed by MDU is too long. Determining the amortization period

[38] See MDU Workpaper I-13.
[39] Direct testimony of Travis R. Jacobson, pp. 15-16.

in this circumstance is a matter of informed judgment that should balance on the one hand the recognition that existing and historical MDU customers have overpaid for the decommissioning costs and deserve to have this overpayment credited back to them in a timely manner and, on the other hand, maintaining rate stability by avoiding a situation in which a large one-time credit is followed by a significant rate increase following the credit's expiration. While the ten-year amortization period proposed by MDU mitigates the concern about rate impact upon the *expiration* of the credit (ten years from now) it does not return this overpayment to current customers in a sufficiently timely manner nor does it recognize that the Company's filed case calls for a dramatic rate increase at *this* time. Moreover, MDU's filed case proposes a net increase in annual depreciation expense $616,848 even after taking account of this credit.[40] I find it troubling that current customers face an increase in net depreciation expense of this magnitude after having overpaid $6.7 million in decommissioning costs through current and previous depreciation rates.

Q. WHAT IS YOUR RECOMMENDATION FOR AMORTIZATION OF DECOMMISSIONING OVER-RECOVERY?

A. In this situation, I believe a five-year amortization period is most appropriate. I believe such an amortization period best balances the public interest in crediting current customers for their past overpayment in a timely manner with that of long-term rate stability. In addition, a five-year amortization period has the benefit of completely

[40] *Id.*, p. 16.

offsetting the increase in net depreciation expense proposed by MDU for its existing plant.

Accordingly, I have prepared an adjustment that amortizes the crediting of the over-recovery over a five-year period. This adjustment is presented in Exhibit KCH-7. I estimate that this adjustment reduces the Montana revenue deficiency by **$673,239** relative to MDU's filed case.

IV. BIG STONE DEPRECIATION EXPENSE UPDATE

Q. PLEASE DESCRIBE THE DEPRECIATION RATES FOR BIG STONE PLANT UTILIZED BY MDU IN ITS DIRECT FILING.

A. MDU's Direct Filing utilized the depreciation rates developed in the Electric Division Depreciation Study as of December 31, 2014 by MDU witness Earl M. Robinson. This study resulted in an average depreciation rate for the depreciable Big Stone Plant of 3.00%.[41]

Q. HAVE THERE BEEN ANY SUBSEQUENT UPDATES TO THE BIG STONE PLANT DEPRECIATION RATES?

A. Yes, as explained in MDU's updated response to Data Request LCG-003, the joint owners of the Big Stone Plant, Ottertail Power and Northwestern Energy, have used a probable retirement year of 2046, rather than 2027 as utilized in MDU's Direct Filing. MDU states that it will adopt the probable retirement year of 2046 for accounting consistency, while noting that the Big Stone environmental project does not appear to support a life extension of 19 years. MDU provided the updated Big Stone depreciation

[41] See Exhibit EMR-1, Electric Division Depreciation Study, Table 1-Plant Site, p. 2-4.

rates in its updated response to LCG-003, resulting in an average depreciation rate for the depreciable Big Stone Plant of 1.40%.[42]

Q. HAVE YOU REFLECTED THE UPDATED BIG STONE PLANT DEPRECIATION RATES CORRESPONDING TO THE 2046 RETIREMENT YEAR?

A. Yes, this adjustment to the Big Stone Plant depreciation rates is presented in Exhibit KCH-8. I estimate that this adjustment reduces the Montana revenue requirement by $**216,071** relative to MDU's filed case. This adjustment estimates the impact of the updated depreciation rates on the average 2015 Big Stone plant balances, excluding the Big Stone AQCS addition. The impact of the updated depreciation rates on the Big Stone AQCS Project is incorporated in my adjustment for the AQCS Project, presented in Exhibit KCH-2. The ancillary deferred income tax impacts have not been included in my adjustment and I recommend that these impacts be quantified by MDU as part of its compliance filing or in a supplemental filing in this case.

V. GENERATION OVERHAUL EXPENSE

Q. HOW IS MDU PROPOSING TO INCORPORATE ITS GENERATION OVERHAUL EXPENSE IN ITS REVENUE REQUIREMENT?

A. As reported in the direct testimony of Mr. Jacobson, MDU's Adjustment No. 13 reflects the expenses associated with the Company's Big Stone and Coyote generating stations to reflect operations for 2015. MDU's adjustment incorporates major overhaul costs for Big Stone Plant, as the Company normally performs major annual overhauls on a rotating

[42] MDU's Updated Response to Data Request LCG-003, File LCG - 003 - DEPR TABLES MDU-Elec, which is provided in Exhibit KCH-13.

basis and no major annual overhauls were scheduled in 2014.[43] However, MDU explained in discovery that 2014 expenses included costs associated with an overhaul planned for Lewis & Clark in 2015.[44] I believe that MDU's proposed revenue requirement includes the Lewis & Clark overhaul expenses incurred in 2014, as well as the projected Big Stone Plant 2015 overhaul expenses.

Q. DO YOU AGREE WITH THIS PROPOSED RATEMAKING TREATMENT FOR GENERATION OVERHAUL EXPENSE?

A. No, I do not. The overhaul schedule for a generating facility generally follows a multi-year cycle, which is consistent with Mr. Jacobson's discussion of MDU's practices. Consequently, for a given plant, a year in which expense for a planned overhaul is high may be followed by years of little or no expense. For ratemaking purposes, it is preferable to use a normalization technique for this expense item because the actual overhaul expense in a given test period may not be representative of annual overhaul expense over time. A reasonable normalization technique for setting test year overhaul expense is to use an historical average over a multi-year period, rather than the expense experienced (or projected) for a single year. This approach smoothes out the otherwise volatile pattern of annual costs that is typical of generation overhaul expense. Once adopted, this approach should continue to be used in subsequent cases. For the purposes of this case, I recommend that generation overhaul expense be based on the historical five-year annual average for this expense for the years 2010 through 2014. Consistent

[43] Direct testimony of Travis R. Jacobson, p. 11.

[44] MDU's Response to Data Request LCG-044(b), and Attachment A, which are provided in Exhibit KCH-13.

with this recommendation, I have prepared a generation overhaul expense adjustment using this approach, which is presented in Exhibit KCH-9.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR RECOMMENDED ADJUSTMENT?

A. I estimate that this adjustment reduces the Montana revenue deficiency by **$311,858** relative to MDU's filed case.

VI. COST OF CAPITAL

Q. HAVE YOU INCORPORATED THE EFFECTS OF THE COST-OF-CAPITAL RECOMMENDATIONS OF MR. GORMAN INTO LCG'S RECOMMENDED REVENUE REQUIREMENT?

A. Yes, I have. Mr. Gorman's cost of capital recommendations are incorporated into Exhibit KCH-1, page 2, with interest expense impacts shown in Exhibits KCH-10 and KCH-11. I estimated the impact of Mr. Gorman's cost-of-capital adjustments as applied to LCG's recommended rate base. As compared to MDU's filed case, Mr. Gorman's recommended capital structure reduces the Montana revenue requirement by **$366,063,** his cost of debt adjustment reduces the Montana revenue requirement by **$71,658,** and his return on equity adjustment reduces the Montana revenue requirement by **$479,265**. If Mr. Gorman's cost-of-capital adjustments were applied to MDU's proposed rate base rather than the rate base recommended by LCG, the impact of his adjustments taken in isolation would be larger.

VII. RECOVERY OF DEFERRED PSC AND MCC TAXES

Q. WHAT IS MDU PROPOSING WITH RESPECT TO THE RECOVERY OF DEFERRED PSC AND MCC TAXES?

A. According to the direct testimony of Mr. Jacobson, MDU was authorized, in Docket Nos. N2010.11.1 05 and N2011.10.90, to defer the revenues associated with the change in the PSC and MCC tax rates. In this case, MDU is proposing to recover the deferred PSC and MCC tax for the period beginning October 1, 2010 and utilize the fuel and purchased power cost tracking adjustment mechanism as the vehicle to recover the deferred amounts. Mr. Jacobson calculates the unrecovered balance to be $399,742 for the period October 2010 through March 2015.

MDU proposes to recover the deferred amount from its customers over a one-year period on a per kWh basis based on projected sales and, as I noted above, to utilize the fuel and purchased power cost tracking adjustment mechanism as the means to recover the cost. According to the proposal, each year the Company would update the recovery rate in conjunction with the annual change in the unreflected fuel cost adjustment in order to recover or return the deferred account balance as of March 31st of each year. Mr. Jacobson states that the adjustment will not be included in the cost of fuel and purchased power, but rather the Company will use the mechanism as the means of recovering the taxes. Mr. Jacobson estimates that the initial recovery rate to recover the under recovered balance of $399,742 over one year is approximately 0.0500 cents per kWh.[45]

Q. WHAT IS YOUR ASSESSMENT OF MDU'S PROPOSAL FOR RECOVERING DEFERRED PSC AND MCC TAXES?

A. I recommend that the recovery of the $399,742 balance be extended over three years (without carrying charge) to mitigate the impact on customers. The unrecovered balance

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[45] Direct testimony of Travis R. Jacobson, pp. 24-25.

was built up over 4½ years. It is not reasonable to attempt to extinguish this balance in one year given its magnitude.

Further, it appears to me that the reason an unrecovered balance has been accrued in the first place is due to faulty rate design. The PSC and MCC taxes levied on MDU are percentage gross-ups of total revenues. As discussed by LCG witness Stephen Baron the most straightforward and equitable manner in which to recover these costs from customers is on the same percentage basis applied to customer bills. However, rather than recovering the taxes in this straightforward and simple way, MDU apparently converted the charge into a kWh component that was embedded in base rates, as I understand MDU's explanation provided in discovery.[46] Converting the percentage gross-up into a kWh component not only unreasonably shifts the cost recovery responsibility among customer classes, it also assures that over time there is likely to be a mismatch between the amount of tax assessed on the Company and revenues recovered from customers to pay the taxes, giving rise to the problem that MDU is attempting to remedy in this case. As Mr. Baron will discuss, this problem can be avoided in the first place by adopting a recovery rate design that appropriately matches the cost being recovered.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF CHANGING THE AMORTIZATION PERIOD FROM ONE YEAR TO THREE YEARS?

A. The $399,742 tax shortfall that MDU is proposing to recover in the next year is <u>not</u> included in the $11.7 million increase that the Company is proposing in this case, but is

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[46] See MDU's (somewhat vague) Response to Data Request LCG-047(b), which is provided in Exhibit KCH-13.

in addition to it. Moving to a three-year amortization will reduce this additional, isolated cost component by **$266,497** in the rate effective year.[47] Because this cost component is not included in the revenue requirement increase proposed by the Company, I have not shown my adjustment as a reduction to the requested revenue requirement filed by MDU.

VIII. BASE FUEL RATE

Q. DO THE ADJUSTMENTS PRESENTED IN YOUR DIRECT TESTIMONY HAVE ANY IMPLICATIONS FOR MDU'S BASE FUEL RATE?

A. Yes. As I noted above, my adjustments to the test period treatment of the four major plant additions results in an increase in fuel and purchased power expense, which I have incorporated into my net revenue requirement impact. For example, my test period treatment of the Thunder Spirit Wind Farm results in a reduction of $5,228,156 of non-fuel revenue requirement and an increase in fuel and purchased power expense of $3,372,692 for a net reduction of $1,855,463, which is reported in Table KCH-1 above.

Viewing the base fuel rate in isolation, my adjustments result in an increase in the proposed base fuel rate to $.02870/kWh compared to the $.02517/kWh rate proposed by MDU. This calculation is shown in Exhibit KCH-12. However, I wish to emphasize that the overall reduction in the revenue deficiency of $9,318,005 being recommended by LCG as reported in Table KCH-1 already includes the net effect of this increase in the base fuel rate.

Q. DOES YOUR PROPOSED BASE FUEL RATE INCLUDE REAGENT COSTS AS PROPOSED BY MDU?

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[47] This is calculated by multiplying the $399,742 tax shortfall by 2/3.

A. No, I have kept recovery of regent expense in base rates, but outside of the base fuel rate. I recommend against including reagent expense in the base fuel rate, where it would be eligible for recovery through the Fuel and Purchased Power Cost Tracking Adjustment. The Commission should be cautious about expanding the list of items eligible for recovery through tracking mechanisms, as doing so shifts risks to customers and diminishes the utility's incentives to be as efficient as possible. I see no compelling reason to expand the definition of items included in the fuel tracker at this time.

IX. ENVIRONMENTAL COST RECOVERY RIDER

Q. WHAT HAS MDU PROPOSED REGARDING AN ENVIRONMENTAL COST RECOVERY RIDER ("ECRR")?

A. According to the direct testimony of Tamie A. Aberle and MDU's proposed tariff, the proposed ECRR (Rate 98) would recover MDU's projected costs of complying with federal and state environmental mandates, including projected capital costs, operating expenses, depreciation expense, and taxes. Eligible costs are those not included in the rates established in the most recent general rate case. MDU has proposed to allocate ECRR costs to rate classes using the Average and Excess Demand allocation factor, and to design the ECRR as a per-kWh charge using projected kWh sales. MDU has proposed to adjust the ECRR annually (or as authorized by the Commission) and to true-up any over- or under-collection based on actual expenditures for the preceding twelve month period. MDU has proposed an initial ECRR rate of 0.000¢/kWh.[48]

Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED ECRR?

[48] Direct Testimony of Tamie A. Aberle, p. 9 and Exhibit No.___(TAA-3).

A. I recommend that the proposed ECRR be rejected. If adopted, the ECRR would be a vehicle for levying significant charges on MDU customers without the scrutiny of a rate case. It is an example of unwarranted single-issue ratemaking.

Q. WHAT IS SINGLE-ISSUE RATEMAKING?

A. Single-issue ratemaking occurs when utility rates are adjusted in response to a change in cost or revenue items considered in isolation. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers the standard practice is to review and consider all relevant factors, rather than just certain factors in isolation. Considering some costs in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. For example, the proposed ECRR would allow MDU to earn a return on its new investment and charge customers for depreciation expenses associated with that new investment without recognizing that its existing rate base would have depreciated to a lower value at the time the ECRR is charged to customers. In my opinion, the proposed ECRR is a classic example of an application of single-issue ratemaking that is not in the public interest. The Commission should view such proposals with great wariness. I recommend that it be rejected.

Q. WHAT ABOUT THE PRESSURE THAT MANY UTILITIES ARE FACING TO COMPLY WITH ENVIRONMENTAL REGULATIONS?

A. I do not dispute that utilities are facing pressure to comply with environmental regulations. However, I do not believe that an annual pass-through mechanism will encourage the most cost-effective compliance actions. Recent experience in the western U.S. shows that environmental upgrade decisions are sometimes modified when utilities are required to consider a broad range of alternatives as part of an approval process required by state utility regulators.

For example, within the past few years PacifiCorp changed its plans to invest in environmental upgrades at its Naughton No. 3 coal plant as part of an economic evaluation required by the Wyoming Public Service Commission for new environmental investments. Rather than continue with its previously-announced plans to upgrade the coal facility, PacifiCorp determined, based on the analysis undertaken in response to testimony filed by intervenors, that it would be more cost-effective on a risk-adjusted basis to convert the plant to natural gas.[49] Had an annual pass-through mechanism been available, PacifiCorp may very well have proceeded with its original plans to upgrade its coal facilities. Instead, PacifiCorp was required to present a full range of investment alternatives as part of a public process before any funding could be approved (including through a general rate case).

Before considering an annual rider to recover MDU's environmental upgrade costs, it would be wise for the Commission to require that the efficacy of these investments be subject to a process that will allow for Commission and stakeholder review well in advance of the arrival of the projects as proposed additions to rate base.

[49] Wyoming Public Service Commission, Docket No. 2000-400-EA-11. Order Granting Motion to Withdraw Application, July 19, 2012 at 1.

The examination should be structured to shed light on the expected revenue requirement impact on customers, including potential changes in depreciation expense, which is anticipated from these investments relative to the cost of alternative actions.

Q. WHY IS IT IMPORTANT TO CONSIDER THE IMPACT ON FUTURE DEPRECIATION EXPENSE WHEN EVALUATING ENVIRONMENTAL UPGRADES?

A. Environmental upgrades are generally depreciated using the same depreciation rate as the existing rate base. Consequently, when environmental projects come into rate base at the current time, the depreciation expense reflects a long asset life. However, asset lives are subject to revision in future depreciation studies as existing plants approach retirement. This means that the depreciation expense for environmental upgrades may be subject to significant upward revision in future rate cases. The upshot is that expensive environmental upgrades may have future ratemaking consequences for customers when the plants are retired, an implication that is not readily apparent at the time the environmental investments first come into rates.

X. TRANSMISSION COST RECOVERY RIDER

Q. WHAT HAS MDU PROPOSED REGARDING A TRANSMISSION COST RECOVERY RIDER ("TCRR")?

A. According to MDU's proposed tariff, the proposed TCRR (Rate 99) would recover transmission-related capital and operating costs, including new or modified transmission facilities, as well as federally regulated costs to increase transmission capacity or reliability. Eligible costs are those not included in the rates established in the most recent general rate case. The adjustment would be based on MDU's transmission costs as of September 30th of each year, and would be designed as a per-kWh charge using projected kWh sales. The TCRR would also include a true-up component. MDU has proposed an initial TCRR rate of 0.000¢/kWh.[50]

Q. WHAT IS YOUR ASSESSMENT OF THE PROPOSED TCRR?

A. I recommend that the proposed TCRR be rejected. Similar to the proposed ECRR, the TCRR is an example of unwarranted single-issue ratemaking. The arguments I offered in opposition to the ECRR on these grounds apply equally to the TCRR proposal. Considering transmission costs in isolation might cause a rate increase due to this one cost area without recognizing counterbalancing savings in another area. Such a mechanism would also allow for the recovery of potentially millions of dollars without the benefit of a rate case review. In my opinion, adoption of this type of mechanism is not in the public interest.

XI. WHOLESALE SALES MARGINS

Q. PLEASE DESCRIBE MDU'S PROPOSED CHANGES TO THE TREATMENT OF WHOLESALE SALES MARGINS.

A. MDU has proposed to reduce customers' share of incremental wholesale sales margins reflected in the Fuel and Purchased Power Cost Tracking Adjustment (Rate 58) from the current 90% to 85%, while setting the wholesale sales margins included in base rates at $0.

According to the direct testimony of Mr. Jacobson, base rates currently include $101,000 of sales for resale margins, as established in Docket No. D2010.8.82.[51] Through Rate 58, customers can be charged (or credited) with 90% of the difference

[50] See Exhibit No.___(TAA-4).
[51] Direct Testimony of Travis R. Jacobson, p. 5.

between actual sales for resale margins and the level in base rates, while the Company absorbs (or retains) 10%. According to Mr. Jacobson, the sales for resale margins in 2014 were $41,795, and no sales for resale occurred during January through May of 2015. MDU has proposed to reflect zero base wholesale sales margins, and to revise the sharing mechanism so that customers receive 85% of any wholesale sales margins through Rate 58, with the Company retaining 15%. MDU has proposed a corresponding revision to the treatment of wholesale sales margins for Contract Service Rate 35.

Q. WHAT IS YOUR ASSESSMENT OF MDU'S PROPOSAL?

A. I believe the movement to an 85/15 sharing arrangement for wholesale sales margins is reasonable if, and only if, it is also accompanied by a change in the sharing arrangement for the fuel and purchased power cost tracking adjustment to the same 85/15 split.

Incentives are important for ensuring that utilities seek opportunities for wholesale sales as well as for managing their fuel costs. While the current 90/10 sharing arrangement sends some incentive to the utility to manage its fuel costs efficiently the incentive would be more robust if the sharing arrangement moved closer toward a 70/30 split. In my opinion, this latter arrangement, which is in effect in the PacifiCorp service territories in Wyoming and Utah, provides a critical incentive for the utility to manage its costs and it strikes a reasonable balance between customers and shareholders with respect to the sharing of risks associated with deviations in fuel and purchased power costs relative to what is established in rates.

In seeking to move to an 85/15 split for wholesale sales margins, MDU is recognizing the importance of financial incentives to motivate and reward a utility for taking actions to lower costs for customers. These incentives are equally important when it comes to managing fuel and purchased power costs. Consequently, the sharing mechanism should be the same for wholesale sales margins and the fuel and purchased power cost adjustment mechanism. It is reasonable for <u>both</u> sharing bands to be moved from the current 90/10 to 85/15, but only if both are moved in tandem. It would <u>not</u> be reasonable to move the wholesale sales margins sharing to 85/15 while retaining a 90/10 sharing mechanism for fuel and purchased power costs.

Q. WHAT IS YOUR ASSESSMENT OF MDU'S PROPOSAL TO SET WHOLESALE SALES MARGINS AT ZERO IN BASE RATES IN THIS CASE?

A. When a sharing mechanism is applicable to wholesale sales margins it is important that base rates established in a general rate case incorporate a level of wholesale sales margins that reasonably reflects test period levels. Otherwise, if the sharing mechanism is *defined* as always assuming a zero-base for wholesales sales margin, the sharing mechanism will unreasonably transfer a portion of normally-expected test period wholesale sales margins to the utility. This is turn would create a situation in which the rates set in a general rate case would actually be *above* that which is needed to provide the utility a reasonable opportunity to earn its authorized rate of return (by the amount of normally-expected test period margins transferred to the utility).

In this particular proceeding, given the decline of MDU's off-system sales margins to near zero, I believe that establishing base rates with an assumption of zero off-system sales margins is not unreasonable. However, this treatment should <u>not</u> be adopted as a general ratemaking practice, but only as being reasonably reflective of actual test period margins.

XII. DOCUMENTATION OF DATA RESPONSES RELIED UPON

Q. HAVE YOU PROVIDED COPIES OF THE DATA RESPONSES YOU RELIED UPON IN PREPARING YOUR ANALYSIS?

A. Yes. Data responses that I relied upon are provided in Exhibit KCH-13.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-1

MONTANA LARGE CUSTOMER GROUP
PROJECTED OPERATING INCOME AND RATE OF RETURN
REFLECTING ADDITIONAL REVENUE REQUIREMENTS
ELECTRIC UTILITY - MONTANA

Line No.	Description	Before Additional Revenue Requirements 1/	Additional Revenue Requirements		Reflecting Additional Revenue Requirements
	(A)	(B)	(C)		(D)
1	**Operating Revenues**				
2	Sales	$55,604,814	**$2,437,539**		$58,042,353
3	Sales for Resale	0			0
4	Other	2,222,284			2,222,284
5	Total Revenues	57,827,098	2,437,539		60,264,637
6	**Operating Expenses**				
7	Operation and Maintenance				
8	Fuel and Purchased Power Expense	23,355,546			23,355,546
9	Other O&M Expense	17,308,721			17,308,721
10	Total O&M Expense	40,664,267			40,664,267
11	Depreciation Expense	6,689,713			6,689,713
12	Taxes Other Than Income Expense	4,643,999	7,313	2/	4,651,312
13	Current Income Tax Expense	(8,813,528)	957,205	2/	(7,856,323)
14	Deferred Income Tax Expense	9,306,642			9,306,642
15	Total Expenses	52,491,094	964,518		53,455,612
16	Operating Income	$5,336,004	$1,473,021		$6,809,025
17	**Total Rate Base**	$96,540,834			$96,540,834
18	***Rate of Return***	**5.527%**			**7.053%**

1/ See Exhibit KCH-1, page 3.
2/ Reflects taxes at 39.3875% after deducting Consumer Counsel tax of 0.1% and PSC tax of 0.2%.

MONTANA LARGE CUSTOMER GROUP
AVERAGE UTILITY CAPITAL STRUCTURE
TWELVE MONTHS ENDING DECEMBER 31, 2014
PRO FORMA 2015

	LCG Witness:		*Gorman*	*Gorman*	
Line No.	**Description**	**Amount**	**Weight**	**Cost**	**Weighted Cost**
	(A)	(B)	(C)	(D)	(E)
1	Long Term Debt	$505,460,413	43.887%	5.780%	2.537%
2	Short Term Debt	99,623,527	8.650%	1.631%	0.141%
3	Preferred Stock	15,258,600	1.325%	4.579%	0.061%
4	Common Equity	531,387,131	46.138%	9.350%	4.314%
5	Total	$1,151,729,671	100.000%		7.053%

MONTANA LARGE CUSTOMER GROUP
INCOME STATEMENT
ELECTRIC UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2014
PRO FORMA

Line No.	Description	Per Books	MDU Pro Forma Adjustments	MDU Pro Forma	LCG Adjustments	LCG Pro Forma
	(A)	(B)	(C)	(D)	(E)	(F)
1	**Operating Revenues**					
2	Sales	$55,454,440	$150,374	$55,604,814	$0	$55,604,814
3	Sales for Resale	232,169	(232,169)	0	0	0
4	Other	2,506,951	(284,667)	2,222,284	0	2,222,284
5	Total Revenues	58,193,560	(366,462)	57,827,098	0	57,827,098
6	**Operating Expenses**					
7	Operation and Maintenance					
8	Fuel and Purchased Power Expense	22,311,650	(1,803,587)	20,508,063	2,847,483	23,355,546
9	Other O&M Expense	15,814,581	3,447,455	19,262,036	(1,953,315)	17,308,721
10	Total O&M Expense	38,126,231	1,643,868	39,770,099	894,168	40,664,267
11	Depreciation Expense	6,901,084	4,608,077	11,509,161	(4,819,448)	6,689,713
12	Taxes Other Than Income Expense	4,080,303	617,219	4,697,522	(53,523)	4,643,999
13	Current Income Tax Expense	(4,064,984)	(13,304,337)	(17,369,321)	8,555,793	(8,813,528)
14	Deferred Income Tax Expense	5,966,982	7,080,844	13,047,826	(3,741,184)	9,306,642
15	Total Expenses	51,009,616	645,671	51,655,287	835,807	52,491,094
16	Operating Income	$7,183,944	($1,012,133)	$6,171,811	($835,807)	$5,336,004
17	**Total Rate Base**	$87,013,106	$87,944,242	$174,957,348	($78,416,514)	$96,540,834
18	***Rate of Return***	8.256%		3.528%		5.527%

MONTANA LARGE CUSTOMER GROUP
RATE BASE
ELECTRIC UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2014
PRO FORMA

Line No.	Description	2014	MDU Pro Forma Adjustments	MDU Pro Forma	LCG Adjustments	LCG Pro Forma
	(A)	(B)	(C)	(D)	(E)	(F)
1	Electric Plant in Service	$236,462,751	$104,374,441	$340,837,192	($89,089,292)	$251,747,900
2	Accumulated Reserve for Depreciation	123,710,867	8,209,219	131,920,086	(4,100,528)	127,819,558
3	Net Electric Plant in Service	112,751,884	96,165,222	208,917,106	(84,988,763)	123,928,343
4	Additions					
5	Materials and Supplies	2,956,360	(59,974)	2,896,386	0	2,896,386
6	Fuel Stocks	1,258,391	(51,222)	1,207,169	0	1,207,169
7	Prepayments	40,434	120,008	160,442	0	160,442
8	Unamortized Loss on Debt	893,137	(98,461)	794,676	0	794,676
9	Decommissioning of Retired Plants	(121,716)	16,984	(104,732)	0	(104,732)
10	Provision for Pension and Benefits	10,876	491,293	502,169	0	502,169
11	Provision for Injuries and Damages	3,382,275	50,168	3,432,443	0	3,432,443
12	Total Additions	8,419,757	468,796	8,888,553	0	8,888,553
13	Total Before Deductions	$121,171,641	$96,634,018	$217,805,659	($84,988,763)	$132,816,896
14	Deductions					
15	Accumulated Deferred Income Taxes	32,840,906	9,148,165	41,989,071	(6,572,249)	35,416,822
16	Accumulated Investment Tax Credits	0	0	0	0	0
17	Customer Advances	1,317,629	(458,389)	859,240	0	859,240
18	Total Deductions	34,158,535	8,689,776	42,848,311	(6,572,249)	36,276,062
19	**Total Rate Base**	$87,013,106	$87,944,242	$174,957,348	($78,416,514)	$96,540,834

MONTANA LARGE CUSTOMER GROUP
INCOME STATEMENT ADJUSTMENTS
ELECTRIC UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2014
PRO FORMA

Line No.	Description	1 Big Stone - AQCS Project Adjustment	2 Lewis & Clark - MATS Project Adjustment	3 Lewis & Clark - RICE Units Adjustment	4 Thunder Spirit Wind Farm Adjustment	5 Transmission Expense Adjustment	6 Decommissioning Over-Recovery Adjustment
	LCG Witness:	*Higgins*	*Higgins*	*Higgins*	*Higgins*	*Higgins*	*Higgins*
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Operating Revenues						
2	Sales						
3	Sales for Resale						
4	Other						
5	Total Revenues	0	0	0	0	0	0
6	Operating Expenses						
7	Operation and Maintenance						
8	Fuel and Purchased Power Expense	(247,609)	(27,516)	(2,463)	3,372,692		
9	Other O&M Expense	(91,216)	0	(105,880)	(711,534)	(981,384)	
10	Total O&M Expense	(338,825)	(27,516)	(108,343)	2,661,158	(981,384)	0
11	Depreciation Expense	(731,314)	(139,273)	(224,181)	(2,825,586)		(671,219)
12	Taxes Other Than Income Expense				(53,523)		
13	Current Income Tax Expense	2,093,375	203,814	275,927	5,158,352	386,543	264,376
14	Deferred Income Tax Expense	(1,342,033)	(107,366)	(56,630)	(2,235,155)		
15	Total Expenses	(318,797)	(70,340)	(113,226)	2,705,246	(594,841)	(406,843)
16	Operating Income	$318,797	$70,340	$113,226	($2,705,246)	$594,841	$406,843
17	Estimated Rev. Req't Impact	($2,584,324)	($496,564)	($1,279,164)	($1,855,463)	($984,337)	($673,239)

Line No.	Description	7 Depreciation Update - Big Stone Adjustment	8 Generation Overhaul Expense Adjustment	9 F&PP Definition - Reagent Cost Reversal	10 Capital Structure Adjustment	11 Cost of Debt Reversal	12 Total
	LCG Witness:	*Higgins*	*Higgins*	*Higgins*	*Gorman*	*Gorman*	
	(A)	(H)	(I)	(J)	(K)	(L)	(M)
18	Operating Revenues						
19	Sales						$0
20	Sales for Resale						0
21	Other						0
22	Total Revenues	0	0	0	0	0	0
23	Operating Expenses						
24	Operation and Maintenance						
25	Fuel and Purchased Power Expense			(247,621)			2,847,483
26	Other O&M Expense		(310,922)	247,621			(1,953,315)
27	Total O&M Expense	0	(310,922)	0	0	0	894,168
28	Depreciation Expense	(227,875)					(4,819,448)
29	Taxes Other Than Income Expense						(53,523)
30	Current Income Tax Expense	88,588	122,465		(65,783)	28,137	8,555,793
31	Deferred Income Tax Expense						(3,741,184)
32	Total Expenses	(139,287)	(188,458)	0	(65,783)	28,137	835,807
33	Operating Income	$139,287	$188,458	$0	$65,783	($28,137)	($835,807)
34	Estimated Rev. Req't Impact	($216,071)	($311,858)	$0			

MONTANA LARGE CUSTOMER GROUP
RATE BASE ADJUSTMENTS
ELECTRIC UTILITY - MONTANA
TWELVE MONTHS ENDED DECEMBER 31, 2014
PRO FORMA

Line No.	Description	1 Big Stone - AQCS Project Adjustment	2 Lewis & Clark - MATS Project Adjustment	3 Lewis & Clark - RICE Units Adjustment	4 Thunder Spirit Wind Farm Adjustment	5 Depreciation Update - Big Stone Adjustment	6 Total
	LCG Witness:	*Higgins*	*Higgins*	*Higgins*	*Higgins*	*Higgins*	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	Electric Plant in Service	($20,161,068)	($3,372,175)	($9,032,223)	($56,523,826)		($89,089,292)
2	Accumulated Reserve for Depreciation	(757,860)	(151,354)	(243,627)	(2,832,852)	(114,836)	(4,100,528)
3	Net Electric Plant in Service	(19,403,208)	(3,220,821)	(8,788,596)	(53,690,974)	114,836	(84,988,763)
4	Additions						
5	Materials and Supplies						0
6	Fuel Stocks						0
7	Prepayments						0
8	Unamortized Loss on Debt						0
9	Decommissioning of Retired Plants						0
10	Provision for Pension and Benefits						0
11	Provision for Injuries and Damages						0
12	Total Additions	0	0	0	0	0	0
13	Total Before Deductions	($19,403,208)	($3,220,821)	($8,788,596)	($53,690,974)	$114,836	($84,988,763)
14	Deductions						
15	Accumulated Deferred Income Taxes	(3,023,041)	(193,193)	(93,543)	(3,262,473)		(6,572,249)
16	Accumulated Investment Tax Credits						0
17	Customer Advances						0
18	Total Deductions	(3,023,041)	(193,193)	(93,543)	(3,262,473)	0	(6,572,249)
19	Total Rate Base	($16,380,167)	($3,027,629)	($8,695,053)	($50,428,501)	$114,836	($78,416,514)

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-2

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Big Stone AQCS Project Adjustment

Line No.	Income Statement	Montana Amount
	(A)	(B)
1	**Operating Revenues**	
2	Sales	
3	Sales for Resale	
4	Other	
5	Total Revenues	$0
6	**Operating Expenses**	
7	Operation and Maintenance	
8	Fuel and Purchased Power Expense	($247,609)
9	Other O&M Expense	(91,216)
10	Total O&M Expense	(338,825)
11	Depreciation Expense	(731,314)
12	Taxes Other Than Income Expense	
13	Current Income Tax Expense	2,093,375
14	Deferred Income Tax Expense	(1,342,033)
15	Total Expenses	($318,797)
16	Operating Income	$318,797

Line No.	Rate Base	Montana Amount
	(A)	(B)
17	Electric Plant in Service	($20,161,068)
18	Accumulated Reserve for Depreciation	(757,860)
19	Net Electric Plant in Service	($19,403,208)
20	Additions	
21	Materials and Supplies	
22	Fuel Stocks	
23	Prepayments	
24	Unamortized Loss on Debt	
25	Decommissioning of Retired Plants	
26	Provision for Pension and Benefits	
27	Provision for Injuries and Damages	
28	Total Additions	$0
29	Total Before Deductions	
30	Deductions	
31	Accumulated Deferred Income Taxes	($3,023,041)
32	Accumulated Investment Tax Credits	
33	Customer Advances	
34	Total Deductions	($3,023,041)
35	Total Rate Base	($16,380,167)
36	**Estimated Revenue Requirement Impact:**	
37	Net Income Impact	$318,797
38	MDU Net to Gross Factor	1.65479
39	Net Income RR Impact	($527,542)
40	Rate Base Impact	($16,380,167)
41	MDU Requested Rate of Return on Rate Base	7.588%
42	MDU Net to Gross Factor	1.65479
43	Rate Base RR Impact	($2,056,782)
44	Total Revenue Requirement Impact	($2,584,324)

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Big Stone AQCS Project Adjustment

Line No.	Description (A)	MDU Test Year Amount		LCG Test Year Amount	LCG Recommended Adjustment
1	**Adjustment to Rate Base:**				
2	Steam Plant Additions	$21,841,157	/1	$1,680,089	($20,161,068)
3	Accumulated Depreciation	$760,072	/2	$2,212	($757,860)
4	Accum. DIT	$3,163,125	/5	$140,084	($3,023,041)
5	**Adjustment to Expenses:**				
6	Reagent Expense	$270,119	/3	$22,510	($247,609)
7	Production O&M Expense	$99,508	/4	$8,292	($91,216)
8	Depreciation Expense	$760,072	/2	$28,758	($731,314)
9	**Adjustment to Taxes:**				
10	Deferred Income Tax Expense	$3,163,125	/6	$1,821,092	($1,342,033)
11	Adjustment to Taxes				
12	Tax Deprecation	$8,790,855	/7	$4,652,285	($4,138,570)
13	Book Depreciation	($345,090)	/7	($28,758)	$316,333

Data Sources:
l. MDU Rule 38.5.125, Statement C, p. 8 of 14.
2. MDU Rule 38.5.165, Statement I, p. 8 of 17.
3. MDU Rule 38.5.157, Statement G, p. 5 & 17 of 35.
4. MDU's Workpapers re Statements A-O.pdf, p. G-72 to G-79 and Rule 38.5.157, Statement G, p. 14 of 35.
5. MDU Rule 38.5.175, p. 5 of 8 and Rule 38.5.169, Statement J, p. 15 of 18.
6. MDU Rule 38.5.175, p. 4 of 8 and Rule 38.5.169, Statement J, p. 15 of 18.
7. MDU Rule 38.5.169, Statement J, p. 15 of 18 worksheet.

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Big Stone AQCS Project Adjustment

LCG Rate Base Amount

Line No.	Month	Electric Plant in Service	Depreciation Expense	Accumulated Depreciation
	(A)	(B)	(C)	(D)
1	December 2014	$0		$0
2	January 2015	$0	$0	$0
3	February 2015	$0	$0	$0
4	March 2015	$0	$0	$0
5	April 2015	$0	$0	$0
6	May 2015	$0	$0	$0
7	June 2015	$0	$0	$0
8	July 2015	$0	$0	$0
9	August 2015	$0	$0	$0
10	September 2015	$0	$0	$0
11	October 2015	$0	$0	$0
12	November 2015	$0	$0	$0
13	December 2015	$21,841,157	$28,758	$28,758
14	TY Total		$28,758	
15	13-Mo. Avg.	$1,680,089		$2,212

LCG Operating Expense Amount

Line No.	Month	Reagent Expense	Other Production O&M Expense
	(A)	(B)	(C)
16	January 2015	$0	$0
17	February 2015	$0	$0
18	March 2015	$0	$0
19	April 2015	$0	$0
20	May 2015	$0	$0
21	June 2015	$0	$0
22	July 2015	$0	$0
23	August 2015	$0	$0
24	September 2015	$0	$0
25	October 2015	$0	$0
26	November 2015	$0	$0
27	December 2015	$22,510	$8,292
28	TY Total	$22,510	$8,292

LCG Deferred Income Tax Amount

Line No.	Description	Amount
	(A)	(B)
29	Book Depreciation	$28,758
30	Tax Depreciation[1]	$4,652,285
31	Book/Tax Difference	$4,623,527
32	Deferred Income Tax	$1,821,092
33	Accumulated DIT	$140,084

Note 1. Tax depreciation based on 50% bonus tax depreciation applied to eligible amount plus one month amortization applied to 84 month eligible amount plus 20 year MACRS mid-quarter convention for property placed in service in fourth quarter of year applied to eligible amount (0.938%).

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-3

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Lewis & Clark MATS Project Adjustment

Line No.	Income Statement	Montana Amount
	(A)	(B)
1	Operating Revenues	
2	Sales	
3	Sales for Resale	
4	Other	
5	Total Revenues	$0
6	Operating Expenses	
7	Operation and Maintenance	
8	Fuel and Purchased Power Expense	($27,516)
9	Other O&M Expense	0
10	Total O&M Expense	(27,516)
11	Depreciation Expense	(139,273)
12	Taxes Other Than Income Expense	
13	Current Income Tax Expense	203,814
14	Deferred Income Tax Expense	(107,366)
15	Total Expenses	($70,340)
16	Operating Income	$70,340

Line No.	Rate Base	Montana Amount
	(A)	(B)
17	Electric Plant in Service	($3,372,175)
18	Accumulated Reserve for Depreciation	(151,354)
19	Net Electric Plant in Service	($3,220,821)
20	Additions	
21	Materials and Supplies	
22	Fuel Stocks	
23	Prepayments	
24	Unamortized Loss on Debt	
25	Decommissioning of Retired Plants	
26	Provision for Pension and Benefits	
27	Provision for Injuries and Damages	
28	Total Additions	$0
29	Total Before Deductions	
30	Deductions	
31	Accumulated Deferred Income Taxes	($193,193)
32	Accumulated Investment Tax Credits	
33	Customer Advances	
34	Total Deductions	($193,193)
35	Total Rate Base	($3,027,629)
36	**Estimated Revenue Requirement Impact:**	
37	Net Income Impact	$70,340
38	MDU Net to Gross Factor	1.65479
39	Net Income RR Impact	($116,398)
40	Rate Base Impact	($3,027,629)
41	MDU Requested Rate of Return on Rate Base	7.588%
42	MDU Net to Gross Factor	1.65479
43	Rate Base RR Impact	($380,165)
44	Total RR Impact	($496,564)

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Lewis & Clark MATS Project Adjustment

Line No.	Description	MDU Test Year Amount		LCG Test Year Amount	LCG Recommended Adjustment
	(A)	(B)		(C)	(D)
1	**Adjustment to Rate Base:**				
2	Other Plant Additions	$3,663,366	/1	$291,191	($3,372,175)
3	Accumulated Depreciation	$152,396	/2	$1,042	($151,354)
4	Accum. DIT	$200,345	/5	$7,152	($193,193)
5	**Adjustment to Expenses:**				
6	Reagent Expense (Incremental)	$30,108	/3	$2,593	($27,516)
7	Production O&M Expense	$0	/4	$0	$0
8	Depreciation Expense	$152,396	/2	$13,123	($139,273)
9	**Adjustment to Taxes:**				
10	Deferred Income Tax Expense	$200,345	/6	$92,979	($107,366)
11	Adjustment to Taxes				
12	Tax Deprecation	$661,047	/7	$249,185	($411,861)
13	Book Depreciation	($152,396)	/7	($13,123)	$139,273

Data Sources:
l. MDU Rule 38.5.125, Statement C, p. 8 of 14.
2. MDU Rule 38.5.165, Statement I, p. 8 of 17.
3. MDU Rule 38.5.157, Statement G, p. 5 & 17 of 35.
4. Included with Lewis & Clark - RICE Units.
5. MDU Rule 38.5.175, p. 5 of 8 and Rule 38.5.169, Statement J, p. 15 of 18.
6. MDU Rule 38.5.175, p. 4 of 8 and Rule 38.5.169, Statement J, p. 15 of 18.
7. MDU Rule 38.5.169, Statement J, p. 15 of 18 worksheet.

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Lewis & Clark MATS Project Adjustment

LCG Rate Base Amount

Line No.	Month	Electric Plant in Service	Depreciation Expense	Accumulated Depreciation
	(A)	(B)	(C)	(D)
1	December 2014	$0	$0	$0
2	January 2015	$0	$0	$0
3	February 2015	$0	$0	$0
4	March 2015	$0	$0	$0
5	April 2015	$0	$0	$0
6	May 2015	$0	$0	$0
7	June 2015	$0	$0	$0
8	July 2015	$0	$0	$0
9	August 2015	$0	$0	$0
10	September 2015	$0	$0	$0
11	October 2015	$0	$0	$0
12	November 2015	$122,112	$423	$423
13	December 2015	$3,663,366	$12,700	$13,123
14	TY Total		$13,123	
15	13-Mo. Avg.	$291,191		$1,042

LCG Operating Expense Amount

Line No.	Month	Reagent Expense	Other Production O&M Expense
	(A)	(B)	(C)
16	January 2015	$0	$0
17	February 2015	$0	$0
18	March 2015	$0	$0
19	April 2015	$0	$0
20	May 2015	$0	$0
21	June 2015	$0	$0
22	July 2015	$0	$0
23	August 2015	$0	$0
24	September 2015	$0	$0
25	October 2015	$0	$0
26	November 2015	$84	$0
27	December 2015	$2,509	$0
28	TY Total	$2,593	$0

LCG Deferred Income Tax Amount

Line No.	Description	Amount
	(A)	(B)
29	Book Depreciation	$13,123
30	Tax Depreciation[1]	$249,185
31	Book/Tax Difference	$236,062
32	Deferred Income Tax	$92,979
33	Accumulated DIT	$7,152

Note 1. Tax depreciation based on 50% bonus tax depreciation applied to eligible amount plus one month amortization applied to 60 month eligible amount plus 20 year MACRS mid-quarter convention for property placed in service in fourth quarter of year applied to eligible amount (0.938%).

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-4

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Lewis & Clark - RICE Units Project Adjustment

Line No.	Income Statement	Montana Amount
	(A)	(B)
1	Operating Revenues	
2	Sales	
3	Sales for Resale	
4	Other	
5	Total Revenues	0
6	Operating Expenses	
7	Operation and Maintenance	
8	Fuel and Purchased Power Expense	(2,463)
9	Other O&M Expense	(105,880)
10	Total O&M Expense	(108,343)
11	Depreciation Expense	(224,181)
12	Taxes Other Than Income Expense	
13	Current Income Tax Expense	275,927
14	Deferred Income Tax Expense	(56,630)
15	Total Expenses	(113,226)
16	Operating Income	$113,226

Line No.	Rate Base	Montana Amount
	(A)	(B)
17	Electric Plant in Service	(9,032,223)
18	Accumulated Reserve for Depreciation	($243,627)
19	Net Electric Plant in Service	($8,788,596)
20	Additions	
21	Materials and Supplies	
22	Fuel Stocks	
23	Prepayments	
24	Unamortized Loss on Debt	
25	Decommissioning of Retired Plants	
26	Provision for Pension and Benefits	
27	Provision for Injuries and Damages	
28	Total Additions	0
29	Total Before Deductions	
30	Deductions	
31	Accumulated Deferred Income Taxes	($93,543)
32	Accumulated Investment Tax Credits	
33	Customer Advances	
34	Total Deductions	($93,543)
35	Total Rate Base	($8,695,053)
36	**Estimated Revenue Requirement Impact:**	
37	Net Income Impact	$113,226
38	MDU Net to Gross Factor	1.65479
39	Net Income RR Impact	(187,366)
40	Rate Base Impact	(8,695,053)
41	MDU Requested Rate of Return on Rate Base	7.588%
42	MDU Net to Gross Factor	1.65479
43	Rate Base RR Impact	(1,091,798)
44	Total RR Impact	(1,279,164)

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Lewis & Clark RICE Units Adjustment

Line No.	Description	MDU Test Year Amount		LCG Test Year Amount	LCG Recommended Adjustment
	(A)	(B)		(C)	(D)
1	**Adjustment to Rate Base:**				
2	Other Plant Additions	$9,812,164	/1	$779,941	($9,032,223)
3	Accumulated Depreciation	$245,304	/2	$1,677	($243,627)
4	Accum. DIT	$96,619	/6	$3,076	($93,543)
5	**Adjustment to Expenses:**				
6	Fuel & Purchased Power Expense	$25,487	/4	$26,953	$1,466
7	Reagent Expense	$4,299	/3	$370	($3,929)
8	Production O&M Expense	$96,830	/5	$8,338	($88,492)
9	Administrative & General Expense	$19,027	/5	$1,638	($17,389)
10	Depreciation Expense	$245,304	/2	$21,123	($224,181)
11	**Adjustment to Taxes:**				
12	Deferred Income Tax Expense	$96,619	/7	$39,990	($56,630)
13	Adjustment to Taxes				
14	Tax Deprecation	$490,608	/8	$122,652	($367,956)
15	Book Depreciation	($245,304)	/8	($21,123)	$224,181

Data Sources:
l. MDU Rule 38.5.125, Statement C, p. 8 of 14.
2. MDU Rule 38.5.165, Statement I, p. 8 of 17.
3. MDU Rule 38.5.157, Statement G, p. 5 & 17 of 35.
4. MDU Rule 38.5.157, Statement G, p. 5 of 35 and MDU Workpapers re Statements A-O.pdf, p. G-35.
5. Rule 38.5.157, Statement G, p. 10 of 35.
6. MDU Rule 38.5.175, p. 5 of 8 and Rule 38.5.169, Statement J, p. 15 of 18.
7. MDU Rule 38.5.175, p. 4 of 8 and Rule 38.5.169, Statement J, p. 15 of 18.
8. MDU Rule 38.5.169, Statement J, p. 15 of 18 worksheet.

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Lewis & Clark RICE Units Adjustment

LCG Rate Base Amount

Line No.	Month	Electric Plant in Service	Depreciation Expense	Accumulated Depreciation
	(A)	(B)	(C)	(D)
1	December 2014	$0	$0	$0
2	January 2015	$0	$0	$0
3	February 2015	$0	$0	$0
4	March 2015	$0	$0	$0
5	April 2015	$0	$0	$0
6	May 2015	$0	$0	$0
7	June 2015	$0	$0	$0
8	July 2015	$0	$0	$0
9	August 2015	$0	$0	$0
10	September 2015	$0	$0	$0
11	October 2015	$0	$0	$0
12	November 2015	$327,072	$681	$681
13	December 2015	$9,812,164	$20,442	$21,123
14	TY Total		$21,123	
15	13-Mo. Avg.	$779,941		$1,677

LCG Operating Expense Amount

Line No.	Month	Fuel & Purch. Pwr Expense	Reagent Expense	Other Production O&M Expense
	(A)	(B)	(C)	(D)
16	January 2015		$0	$0
17	February 2015		$0	$0
18	March 2015		$0	$0
19	April 2015		$0	$0
20	May 2015		$0	$0
21	June 2015		$0	$0
22	July 2015		$0	$0
23	August 2015		$0	$0
24	September 2015		$0	$0
25	October 2015		$0	$0
26	November 2015		$12	$322
27	December 2015		$358	$9,655
28	TY Total	$26,953	$370	$9,977

LCG Deferred Income Tax Amount

Line No.	Description	Amount
	(A)	(B)
29	Book Depreciation	$21,123
30	Tax Depreciation[1]	$122,652
31	Book/Tax Difference	$101,529
32	Deferred Income Tax	$39,990
33	Accumulated DIT	$3,076

Note 1. Tax depreciation based on 15 year MACRS mid-quarter convention for property placed in service in fourth quarter of year (1.25%).

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Exhibit KCH-5

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Thunder Spirit Wind Farm Adjustment

Line No.	Income Statement	Montana Amount
	(A)	(B)
1	Operating Revenues	
2	Sales	
3	Sales for Resale	
4	Other	
5	Total Revenues	$0
6	Operating Expenses	
7	Operation and Maintenance	
8	Fuel and Purchased Power Expense	$3,372,692
9	Other O&M Expense	(711,534)
10	Total O&M Expense	2,661,158
11	Depreciation Expense	(2,825,586)
12	Taxes Other Than Income Expense	(53,523)
13	Current Income Tax Expense	5,158,352
14	Deferred Income Tax Expense	(2,235,155)
15	Total Expenses	$2,705,246
16	Operating Income	($2,705,246)

Line No.	Rate Base	Montana Amount
	(A)	(B)
17	Electric Plant in Service	($56,523,826)
18	Accumulated Reserve for Depreciation	(2,832,852)
19	Net Electric Plant in Service	($53,690,974)
20	Additions	
21	Materials and Supplies	
22	Fuel Stocks	
23	Prepayments	
24	Unamortized Loss on Debt	
25	Decommissioning of Retired Plants	
26	Provision for Pension and Benefits	
27	Provision for Injuries and Damages	
28	Total Additions	$0
29	Total Before Deductions	
30	Deductions	
31	Accumulated Deferred Income Taxes	($3,262,473)
32	Accumulated Investment Tax Credits	
33	Customer Advances	
34	Total Deductions	($3,262,473)
35	Total Rate Base	($50,428,501)
36	**Estimated Revenue Requirement Impact:**	
37	Net Income Impact	($2,705,246)
38	MDU Net to Gross Factor	1.65479
39	Net Income RR Impact	$4,476,611
40	Rate Base Impact	($50,428,501)
41	MDU Requested Rate of Return on Rate Base	7.588%
42	MDU Net to Gross Factor	1.65479
43	Rate Base RR Impact	($6,332,075)
44	Total RR Impact	($1,855,463)

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Thunder Spirit Wind Farm Adjustments

Line No.	Description	MDU Test Year Amount		LCG Test Year Amount	LCG Recommended Adjustment
1	**Adjustment to Rate Base:**				
2	Other Plant Additions	$56,669,131	/1	$145,305	($56,523,826)
3	Accumulated Depreciation	$2,833,457	/2	$605	($2,832,852)
4	Accum. DIT	$3,348,083	/5	$85,610	($3,262,473)
5	**Adjustment to Expenses:**				
6	Fuel & Purchased Power Expense	$0	/3	$3,372,692	$3,372,692
7	Production O&M Expense	$698,704	/4	$1,941	($696,763)
8	Administrative and General Expense	$14,812	/4	$41	($14,771)
9	Depreciation Expense	$2,833,457	/2	$7,871	($2,825,586)
10					
11	**Adjustment to Taxes:**				
12	Deferred Income Tax Expense	$3,348,083	/6	$1,112,928	($2,235,155)
13	Adjustment to Taxes				
14	Tax Deprecation	$11,333,826	/7	$2,833,457	($8,500,369)
15	Book Depreciation	($2,833,457)	/7	($7,871)	$2,825,586
16	Taxes Other than Income	$122,749	/8	$69,226	($53,523)
17	Production Tax Credit	$2,536,469	/9	$0	($2,536,469)

Data Sources:
l. MDU Rule 38.5.125, Statement C, p. 8 of 14.
2. MDU Rule 38.5.165, Statement I, p. 8 of 17.
3. MDU Rule 38.5.157, Statement G, p. 5 of 35 and MDU Workpapers re Statements A-O.pdf, p. G-35.
4. Rule 38.5.157, Statement G, p. 11 of 35.
5. MDU Rule 38.5.175, p. 5 of 8 and Rule 38.5.169, Statement J, p. 15 of 18.
6. MDU Rule 38.5.175, p. 4 of 8 and Rule 38.5.169, Statement J, p. 15 of 18.
7. MDU Rule 38.5.169, Statement J, p. 15 of 18 worksheet.
8. MDU's Workpapers re Statements A-O.pdf, p. K-6.
9. Rule 38.5.169, Statement J, p. 10 of 18.

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Thunder Spirit Wind Farm Adjustments

LCG Rate Base Amount

Line No.	Month	Electric Plant in Service	Depreciation Expense	Accumulated Depreciation
	(A)	(B)	(C)	(D)
1	December 2014	$0	$0	$0
2	January 2015	$0	$0	$0
3	February 2015	$0	$0	$0
4	March 2015	$0	$0	$0
5	April 2015	$0	$0	$0
6	May 2015	$0	$0	$0
7	June 2015	$0	$0	$0
8	July 2015	$0	$0	$0
9	August 2015	$0	$0	$0
10	September 2015	$0	$0	$0
11	October 2015	$0	$0	$0
12	November 2015	$0	$0	$0
13	December 2015	$1,888,971	$7,871	$7,871
14	TY Total		$7,871	
15	13-Mo. Avg.	$145,305		$605

LCG Operating Expense Amount

Line No.	Month	Fuel & Purch. Pwr Expense	Other Production O&M Expense
	(A)	(B)	(C)
16	January 2015		$0
17	February 2015		$0
18	March 2015		$0
19	April 2015		$0
20	May 2015		$0
21	June 2015		$0
22	July 2015		$0
23	August 2015		$0
24	September 2015		$0
25	October 2015		$0
26	November 2015		$0
27	December 2015		$1,982
28	TY Total	$3,372,692	$1,982

LCG Deferred Income Tax Amount

Line No.	Description	Amount
	(A)	(B)
29	Book Depreciation	$7,871
30	Tax Depreciation[1]	$2,833,457
31	Book/Tax Difference	$2,825,586
32	Deferred Income Tax	$1,112,928
33	Accumulated DIT	$85,610

Note 1. Tax depreciation based on 5 year MACRS mid-quarter convention for property placed in service in fourth quarter of year (5.00%).

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Thunder Spirit Wind Farm Adjustments

Taxes Other than Income Taxes - North Dakota Wind Tax

Line No.	Description	LCG Recommended Amount
	(A)	(B)
1	Nameplate Capacity (MW)	107.5
2	Capacity-Related Tax ($/kW)	$2.50
3	Total Company Capacity-Related Tax ($)	$268,750
4	Annualized Pro Forma Generation (kWh)	0
5	Generation Tax ($/kWh)	$0.0005
6	Total Company Generation-Related Tax ($)	$0
7	Total Tax - Total Company	$268,750
8	Montana Allocation Factor - Factor 271 (%)	25.758696%
9	Total Tax - Montana Share	$69,226

Production Tax Credit

Line No.	Month	LCG Recommended Amount
	(A)	(B)
10	Annualized Pro Forma Generation (kWh)	0
11	Production Tax Credit ($/kWh)	$0.023
12	Production Tax Credit ($)	$0
13	Montana Allocation Factor - Factor 16 (%)	26.537673%
14	Total Tax - Montana Share	$0

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Exhibit KCH-6

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Transmission Expense Adjustment

Line No.	Income Statement	Montana Amount
	(A)	(B)
1	Operating Revenues	
2	Sales	
3	Sales for Resale	
4	Other	
5	Total Revenues	$0
6	Operating Expenses	
7	Operation and Maintenance	
8	Fuel and Purchased Power Expense	
9	Other O&M Expense	(981,384)
10	Total O&M Expense	(981,384)
11	Depreciation Expense	
12	Taxes Other Than Income Expense	
13	Current Income Tax Expense	386,543
14	Deferred Income Tax Expense	
15	Total Expenses	($594,841)
16	Operating Income	$594,841

Line No.	Rate Base	Montana Amount
	(A)	(B)
17	Electric Plant in Service	
18	Accumulated Reserve for Depreciation	
19	Net Electric Plant in Service	$0
20	Additions	
21	Materials and Supplies	
22	Fuel Stocks	
23	Prepayments	
24	Unamortized Loss on Debt	
25	Decommissioning of Retired Plants	
26	Provision for Pension and Benefits	
27	Provision for Injuries and Damages	
28	Total Additions	$0
29	Total Before Deductions	
30	Deductions	
31	Accumulated Deferred Income Taxes	
32	Accumulated Investment Tax Credits	
33	Customer Advances	
34	Total Deductions	$0
35	Total Rate Base	$0
36	**Estimated Revenue Requirement Impact:**	
37	Net Income Impact	$594,841
38	MDU Net to Gross Factor	1.65479
39	Net Income RR Impact	($984,337)
40	Rate Base Impact	$0
41	MDU Requested Rate of Return on Rate Base	7.588%
42	MDU Net to Gross Factor	1.65479
43	Rate Base RR Impact	$0
44	Total RR Impact	($984,337)

Derivation of LCG Transmission Expense Adjustment

Line No.	Description	12/31/2014 Per Books Montana Amount[1]	MDU Proposed Pro Forma Montana Amount[1]	MDU Proposed Adjustment Montana Amount	MLCG Recommended Pro Forma Montana Amount[2]	MLCG Recommended Adjustment Montana Amount
	(A)	(B)	(C)	(D)	(E)	(F)
1	Facilities Charge	$186,584	$0	($186,584)	$180,015	$180,015

Data Sources:
1. MDU Rule 38.5.157, Statement G, p. 12 of 35, MDU Adjustment No. 11.
2. MDU Response to Data Request LCG-046.

Line No.	Description	12/31/2014 Per Books Montana Amount[1]	MDU Proposed Pro Forma Montana Amount[1,3]	MDU Proposed Adjustment Montana Amount	MLCG Recommended Pro Forma Montana Amount[3]	MLCG Recommended Adjustment Montana Amount
	(A)	(B)	(C)	(D)	(E)	(F)
2	WAPA NITS	$269,476	$0	($269,476)	$269,236	$269,236
3	Increased Transmission Svc Charge	$0	$905,712	$905,712	$89,745	($815,967)
4	Facility Charge Replacement Charge	$0	$445,431	$445,431	$0	($445,431)
5	WAPA NITS Replacement Charge	$0	$269,476	$269,476	$0	($269,476)
6	SPP Network Transmission Svc.	$0	$1,620,619	$1,620,619	$89,745	($1,530,874)
7	MISO Schedule 26 - RECB	$496,785	$598,693	$101,908	$858,347	$259,654
8	Total Transmission - Other	$635,264	$522,299	($112,965)	$362,884	($159,415)
9	Total Subcontract Labor - Transmission	$1,401,525	$2,741,611	$1,340,086	$1,580,212	($1,161,399)
10	Exclude Regional Market Expense Included in Above[2]	($107,391)	($116,825)	($9,434)	($116,825)	$0
11	Total Net Subcontract Labor - Transmission	$1,294,134	$2,624,786	$1,330,652	$1,463,387	($1,161,399)

Data Sources:
1. MDU Rule 38.5.157, Statement G, p. 13 of 35, MDU Adjustment No. 12 Workpaper.
2. MDU Rule 38.5.157, Statement G, p. 30 of 35, MDU Adjustment No. 29.
3. MDU Response to Data Request LCG-046.

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Exhibit KCH-7

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Decommissioning Over-Recovery Amortization Adjustment

Line No.	Income Statement	Montana Amount
	(A)	(B)
1	Operating Revenues	
2	Sales	
3	Sales for Resale	
4	Other	
5	Total Revenues	$0
6	Operating Expenses	
7	Operation and Maintenance	
8	Fuel and Purchased Power Expense	
9	Other O&M Expense	
10	Total O&M Expense	0
11	Depreciation Expense	(671,219)
12	Taxes Other Than Income Expense	
13	Current Income Tax Expense	264,376
14	Deferred Income Tax Expense	
15	Total Expenses	($406,843)
16	Operating Income	$406,843

Line No.	Rate Base	Montana Amount
	(A)	(B)
17	Electric Plant in Service	
18	Accumulated Reserve for Depreciation	
19	Net Electric Plant in Service	$0
20	Additions	
21	Materials and Supplies	
22	Fuel Stocks	
23	Prepayments	
24	Unamortized Loss on Debt	
25	Decommissioning of Retired Plants	
26	Provision for Pension and Benefits	
27	Provision for Injuries and Damages	
28	Total Additions	$0
29	Total Before Deductions	
30	Deductions	
31	Accumulated Deferred Income Taxes	
32	Accumulated Investment Tax Credits	
33	Customer Advances	
34	Total Deductions	$0
35	Total Rate Base	$0
36	**Estimated Revenue Requirement Impact:**	
37	Net Income Impact	$406,843
38	MDU Net to Gross Factor	1.65479
39	Net Income RR Impact	($673,239)
40	Rate Base Impact	$0
41	MDU Requested Rate of Return on Rate Base	7.588%
42	MDU Net to Gross Factor	1.65479
43	Rate Base RR Impact	$0
44	Total RR Impact	($673,239)

MONTANA LARGE CUSTOMER GROUP (LCG)
DECOMMISSIONING OVER-RECOVERY AMORTIZATION ADJUSTMENT
ELECTRIC UTILITY - MONTANA
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2014

Line No.	Function	12/31/2014 Per Books	MDU Pro Forma Adjustments	MDU Pro Forma 1/	LCG Pro Forma Adjustments	LCG Pro Forma
	(A)	(B)	(C)	(D)	(E)	(F)
1	Steam Production	$2,261,946	$893,973	$3,155,919	$0	$3,155,919
2	Other Production	1,800,774	3,538,681	5,339,455	0	5,339,455
3	Total Production	4,062,720	4,432,654	8,495,374	0	8,495,374
4	Transmission	540,745	267,159	807,904	0	807,904
5	Distribution	1,217,917	522,603	1,740,520	0	1,740,520
6	General	148,248	(2,341)	145,907	0	145,907
7	General Intangible	63,028	5,956	68,984	0	68,984
8	Common	244,754	29,578	274,332	0	274,332
9	Common Intangible	227,323	26,341	253,664	0	253,664
10	AFUDC Interest & Depr. on Coyote	168,451	0	168,451	0	168,451
11	Amort. Of Retired Power Plants	(16,984)	0	(16,984)	0	(16,984)
12	Amort. - Unrecovered Plant	242,228	0	242,228	0	242,228
13	Acquisition Adjustment	2,654	(2,654)	0	0	0
14	Decommissioning Over Recovery	0	(671,219)	(671,219)	(671,219)	(1,342,438)
15	Total	$6,901,084	$4,608,077	$11,509,161	($671,219)	$10,837,942

1/ See Rule 385.5.165, Statement I, pages 2 and 8.

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Exhibit KCH-8

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Big Stone (non-AQCS) Depreciation Rate Adjustment

Line No.	Income Statement	Montana Amount
	(A)	(B)
1	Operating Revenues	
2	Sales	
3	Sales for Resale	
4	Other	
5	Total Revenues	$0
6	Operating Expenses	
7	Operation and Maintenance	
8	Fuel and Purchased Power Expense	
9	Other O&M Expense	
10	Total O&M Expense	0
11	Depreciation Expense	(227,875)
12	Taxes Other Than Income Expense	
13	Current Income Tax Expense	88,588
14	Deferred Income Tax Expense	
15	Total Expenses	($139,287)
16	Operating Income	$139,287

Line No.	Rate Base	Montana Amount
	(A)	(B)
17	Electric Plant in Service	
18	Accumulated Reserve for Depreciation	(114,836)
19	Net Electric Plant in Service	$114,836
20	Additions	
21	Materials and Supplies	
22	Fuel Stocks	
23	Prepayments	
24	Unamortized Loss on Debt	
25	Decommissioning of Retired Plants	
26	Provision for Pension and Benefits	
27	Provision for Injuries and Damages	
28	Total Additions	$0
29	Total Before Deductions	
30	Deductions	
31	Accumulated Deferred Income Taxes	
32	Accumulated Investment Tax Credits	
33	Customer Advances	
34	Total Deductions	$0
35	Total Rate Base	$114,836
36	**Estimated Revenue Requirement Impact:**	
37	Net Income Impact	$139,287
38	MDU Net to Gross Factor	1.65479
39	Net Income RR Impact	($230,491)
40	Rate Base Impact	$114,836
41	MDU Requested Rate of Return on Rate Base	7.588%
42	MDU Net to Gross Factor	1.65479
43	Rate Base RR Impact	$14,419
44	Total RR Impact	($216,071)

LCG Big Stone (non-ACQS) Depreciation Expense Adjustment Derivation

Line No.	Big Stone Depreciable Plant (Excluding AQCS)		2015 Depreciation Expense: Montana MDU Proposed Pro Forma 2015 Average Plant[1]	MDU Filed Depreciation Rate[1]	Montana MDU Filed Depreciation Expense[1]	Updated Depreciation Rate[2]	LCG Proposed Depreciation Expense	LCG Depreciation Expense Adjustment	2015 13 Month Average Depreciation Reserve: Estimated MDU Proposed Incremental Dep. Reserve	LCG Proposed Incremental Dep. Reserve	LCG Proposed Dep. Reserve Adjustment
1	Adjustments to Expense										
2	311	Structures & Improvements	2,140,468	0.69%	14,769	0.31%	6,635	(8,134)	7,385	3,314	(4,070)
3	312	Boiler Plant Equipment	8,047,420	3.48%	280,050	1.58%	127,149	(152,901)	140,025	62,688	(77,337)
4	314	Turbogenerator units	2,728,825	3.57%	97,419	1.70%	46,390	(51,029)	48,710	23,192	(25,517)
5	315	Accessory Equipment	950,866	2.33%	22,155	1.21%	11,505	(10,650)	11,078	5,752	(5,326)
6	316	Miscellaneous Equipment	283,581	4.32%	12,251	2.50%	7,090	(5,161)	6,125	3,540	(2,585)
7		Total Depreciation Expense	14,151,160		426,644		198,770	(227,875)	213,322	98,486	(114,836)
8	Adjustment to Rate Base										
9	108	Accumulated Reserve for Depreciation -Steam	(114,836)								

Line	Big Stone with Additions (Spread Equally Through Year)[3]		Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015 Additions
11	311	Structures & Improvements	2,132,863	2,134,131	2,135,398	2,136,666	2,137,933	2,139,201	2,140,468	2,141,736	2,143,003	2,144,271	2,145,538	2,146,806	2,148,073	15,210
12	312	Boiler Plant Equipment	7,680,151	7,741,363	7,802,574	7,863,786	7,924,997	7,986,209	8,047,420	8,108,632	8,169,843	8,231,055	8,292,266	8,353,478	8,414,689	734,538
13	314	Turbogenerator units	2,727,728	2,727,911	2,728,094	2,728,277	2,728,459	2,728,642	2,728,825	2,729,008	2,729,191	2,729,374	2,729,556	2,729,739	2,729,922	2,194
14	315	Accessory Equipment	950,339	950,427	950,515	950,603	950,690	950,778	950,866	950,954	951,042	951,130	951,217	951,305	951,393	1,054
15	316	Miscellaneous Equipment	282,327	282,536	282,745	282,954	283,163	283,372	283,581	283,789	283,998	284,207	284,416	284,625	284,834	2,507
16	Total Big Stone Depreciable Plant (Excluding AQCS)		13,773,408	13,836,367	13,899,325	13,962,284	14,025,242	14,088,201	14,151,160	14,214,118	14,277,077	14,340,035	14,402,994	14,465,952	14,528,911	755,503
17	2015 Depreciation Expense at Updated Rates															2015 Total
18	311	Structures & Improvements	-	551	551	552	552	552	553	553	553	554	554	554	555	6,635
19	312	Boiler Plant Equipment	-	10,152	10,233	10,314	10,394	10,475	10,555	10,636	10,717	10,797	10,878	10,958	11,039	127,149
20	314	Turbogenerator units	-	3,864	3,865	3,865	3,865	3,865	3,866	3,866	3,866	3,866	3,867	3,867	3,867	46,390
21	315	Accessory Equipment	-	958	958	958	959	959	959	959	959	959	959	959	959	11,505
22	316	Miscellaneous Equipment	-	588	589	589	590	590	591	591	591	592	592	593	593	7,090
23	Total Depreciation Expense		-	16,115	16,196	16,278	16,360	16,442	16,523	16,605	16,687	16,768	16,850	16,932	17,014	198,770
24	Incremental Updated Depreciation Reserve															13 Month Average
25	311	Structures & Improvements	-	551	1,103	1,654	2,207	2,759	3,312	3,865	4,418	4,972	5,526	6,081	6,635	3,314
26	312	Boiler Plant Equipment	-	10,152	20,386	30,699	41,094	51,568	62,124	72,760	83,477	94,274	105,152	116,110	127,149	62,688
27	314	Turbogenerator units	-	3,864	7,729	11,594	15,459	19,325	23,190	27,056	30,923	34,789	38,656	42,523	46,390	23,192
28	315	Accessory Equipment	-	958	1,917	2,875	3,834	4,792	5,751	6,710	7,669	8,628	9,587	10,546	11,505	5,752
29	316	Miscellaneous Equipment	-	588	1,177	1,767	2,356	2,946	3,537	4,128	4,719	5,311	5,904	6,496	7,090	3,540
30	Incremental Depreciation Reserve		-	16,115	32,311	48,589	64,949	81,391	97,914	114,519	131,206	147,974	164,824	181,756	198,770	98,486

1. Rule 38.5.165, Statement I, page 3 of 17.
2. MDU's Updated Response to Data Request LCG-003, Attachment File LCG - 003 - DEPR TABLES MDU-Elec.
3. MDU Rule 38.5.125, Statement C, page 3 of 14.

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-9

Montana Large Customer Group (LCG)
Montana General Rate Case - Dec. 2014
Generation Overhaul Expense Adjustment

Line No.	Income Statement	Montana Amount
	(A)	(B)
1	Operating Revenues	
2	Sales	
3	Sales for Resale	
4	Other	
5	Total Revenues	$0
6	Operating Expenses	
7	Operation and Maintenance	
8	Fuel and Purchased Power Expense	
9	Other O&M Expense	(310,922)
10	Total O&M Expense	(310,922)
11	Depreciation Expense	
12	Taxes Other Than Income Expense	
13	Current Income Tax Expense	122,465
14	Deferred Income Tax Expense	
15	Total Expenses	($188,458)
16	Operating Income	$188,458

Line No.	Rate Base	Montana Amount
	(A)	(B)
17	Electric Plant in Service	
18	Accumulated Reserve for Depreciation	
19	Net Electric Plant in Service	$0
20	Additions	
21	Materials and Supplies	
22	Fuel Stocks	
23	Prepayments	
24	Unamortized Loss on Debt	
25	Decommissioning of Retired Plants	
26	Provision for Pension and Benefits	
27	Provision for Injuries and Damages	
28	Total Additions	$0
29	Total Before Deductions	
30	Deductions	
31	Accumulated Deferred Income Taxes	
32	Accumulated Investment Tax Credits	
33	Customer Advances	
34	Total Deductions	$0
35	Total Rate Base	$0
36	**Estimated Revenue Requirement Impact:**	
37	Net Income Impact	$188,458
38	MDU Net to Gross Factor	1.65479
39	Net Income RR Impact	($311,858)
40	Rate Base Impact	$0
41	MDU Requested Rate of Return on Rate Base	7.588%
42	MDU Net to Gross Factor	1.65479
43	Rate Base RR Impact	$0
44	Total RR Impact	($311,858)

Derivation of LCG Generation Overhaul Expense Adjustment

Line No.	Maintenance Expenses		Total Company Big Stone MDU Proposed Major Outage Costs (2015) [1]	Total Company Lewis & Clark Estimated MDU Proposed Major Outage Costs (2014) [2]	Total Company Est. Major Overhaul Exp. Included in MDU Proposed Rev. Req.	Total Company 2010-2014 Estimated Average Major Overhaul Expense [3]	Total Company LCG Proposed Generation Overhaul Adjustment	Montana LCG Proposed Generation Overhaul Adjustment
	(A)		(B)	(C)	(D)	(E)	(F)	(G)
1	511	Maintenance of Structures	90,800		90,800	0	(90,800)	(20,560)
2	512	Maintenance of Boiler Plant	797,822	358,881	1,156,703	415,526	(741,177)	(167,823)
3	513	Maintenance of Electric Plant	973,490		973,490	517,883	(455,607)	(103,162)
4	514	Maintenance of Misc. Steam Plant	85,579		85,579	0	(85,579)	(19,377)
5	**Total Payroll and Other Expenses**		1,947,691	358,881	2,306,572	933,409	(1,373,163)	(310,922)

Allocated on Factor # 15: Integrated System 12 month Peak Demand.
22.64279%

1. MDU Response to Data Request LCG-045, Attachment A.
2. MDU Response to Data Request LCG-044(b), and Attachment A.
3. Five-year average based on MDU Response to Data Request LCG-044(a), Attachment A. Overhaul expense estimated by comparing each overhaul year's expense to the average of non-overhaul years by FERC account.

Historical Generation Maintenance Expenses

(Overhaul Years Outlined)

Account	Coyote Station - 25% Share	2010	2011	2012	2013	2014	2010-2014
510	Maint. Supervision & Eng.	$ 178,334.90	$ 165,274.34	$ 193,826.06	$ 151,389.54	$ 196,129.54	
511	Maintenance of Structures	118,862.41	122,627.44	134,121.79	216,460.26	194,016.80	
512	Maintenance of Boilers	1,222,043.36	1,532,563.60	1,971,196.52	1,369,869.43	1,486,765.29	
513	Maint. of Turbine & Gen.	232,823.81	189,464.56	609,651.56	266,079.67	185,971.52	
514	Maint. Of Misc. Steam Plant	245,392.28	227,350.72	291,572.58	215,068.42	280,335.43	
	Total	$ 1,997,456.76	$ 2,237,280.66	$ 3,200,368.51	$ 2,218,867.32	$ 2,343,218.58	
Overhaul	Maintenance of Boilers	$ -	$ -	$ 568,386.10	$ -	$ -	$ 113,677.22
Overhaul	Maint. of Turbine & Gen.	$ -	$ -	$ 391,066.67	$ -	$ -	$ 78,213.33
	Big Stone Station	**2010**	**2011**	**2012**	**2013**	**2014**	
510	Maint. Supervision & Eng.	$ 122,130.04	$ 134,816.13	$ 151,289.09	$ 148,341.79	$ 135,488.85	
511	Maintenance of Structures	86,303.48	90,949.35	123,035.32	138,215.72	128,433.65	
512	Maintenance of Boilers	815,921.45	1,411,686.69	1,010,462.28	1,000,820.92	1,049,826.09	
513	Maint. of Turbine & Gen.	132,073.88	306,791.51	176,553.25	225,481.06	281,772.19	
514	Maint. Of Misc. Steam Plant	106,595.53	131,678.47	132,635.78	157,415.53	183,330.37	
	Total	$ 1,263,024.38	$ 2,075,922.15	$ 1,593,975.72	$ 1,670,275.02	$ 1,778,851.15	
Overhaul	Maintenance of Boilers	$ -	$ 442,429.01	$ -	$ -	$ -	$ 88,485.80
Overhaul	Maint. of Turbine & Gen.	$ -	$ 102,821.42	$ -	$ -	$ -	$ 20,564.28
	Heskett	**2010**	**2011**	**2012**	**2013**	**2014**	
510	Maint. Supervision & Eng.	$ 1,046.60	$ 759.94	$ 2,884.10		$ 1,614.17	
511	Maintenance of Structures	220,866.03	157,382.57	137,550.51	132,311.96	287,006.46	
512	Maintenance of Boilers	1,620,690.17	1,124,329.63	837,053.75	1,287,440.79	1,463,673.12	
513	Maint. of Turbine & Gen.	487,509.60	280,420.19	158,331.73	1,088,423.58	127,913.04	
514	Maint. Of Misc. Steam Plant	200,397.92	296,192.02	229,247.02	300,528.80	335,528.55	
	Total	$ 2,530,510.32	$ 1,859,084.35	$ 1,365,067.11	$ 2,808,705.13	$ 2,215,735.34	
Overhaul	Maintenance of Boilers	$ 479,004.67	$ -	$ -	$ 145,755.29	$ -	$ 124,951.99
Overhaul	Maint. of Turbine & Gen.	$ 298,621.28	$ -	$ -	$ 899,535.26	$ -	$ 239,631.31
	Lewis & Clark	**2010**	**2011**	**2012**	**2013**	**2014**	
510	Maint. Supervision & Eng.	$ 3,586.12	$ 4,930.21	$ 1,251.91	$ 2,175.54	$ 14,732.45	
511	Maintenance of Structures	81,659.22	303,903.51	169,600.98	53,560.42	115,225.28	
512	Maintenance of Boilers	446,900.89	405,183.37	506,866.56	418,991.82	782,572.98	
513	Maint. of Turbine & Gen.	117,875.92	53,752.01	987,284.09	102,180.14	85,850.66	
514	Maint. Of Misc. Steam Plant	74,849.83	42,631.26	88,545.09	54,035.98	55,361.58	
	Total	$ 724,871.98	$ 810,400.36	$ 1,753,548.63	$ 630,943.90	$ 1,053,742.95	
Overhaul	Maintenance of Boilers	$ -	$ -	83,174.53	$ -	358,880.95	$ 88,411.10
Overhaul	Maint. of Turbine & Gen.	$ -	$ -	897,369.41	$ -	$ -	$ 179,473.88
	Total 5 Year Average						$ 933,408.92

Data Source: MDU Response to Data Request LCG-044(a), Attachment A.

Note: Overhaul expense estimated by comparing each overhaul year's expense to the average of non-overhaul years by FERC account.

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-10

Derivation of Income Tax Adjustment for LCG's Recommended Capital Structure

Line No.	Description	Amount
	(A)	(B)
1	LCG Recommended Test Year Rate Base	$96,540,834
2	MDU Proposed Wtd. Cost of Debt	2.579%
3	LCG Recommended Wtd. Cost of Debt (Capital Structure Only)	2.752%
4	LCG Pro Forma Interest Expense Adjustment [= (Ln. 3 - Ln. 2) x Ln. 1]	$167,016
5	Current Federal/State Income Taxes @ 39.3875% [= 39.3875% x -Ln. 4]	($65,783)

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-11

Derivation of Income Tax Adjustment for LCG's Recommended Cost of Debt

Line No.	Description	Amount
	(A)	(B)
1	LCG Recommended Test Year Rate Base	$96,540,834
2	LCG Recommended Wtd. Cost of Debt (Capital Structure Only)	2.752%
3	LCG Recommended Adjusted Wtd. Cost of Debt	2.678%
4	LCG Pro Forma Interest Expense Adjustment [= (Ln. 3 - Ln. 2) x Ln. 1]	($71,440)
5	Current Federal/State Income Taxes @ 39.3875% [= 39.3875% x -Ln. 4]	$28,139

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-12

MONTANA LARGE CUSTOMER GROUP
ADJUSTED FUEL AND PURCHASED POWER EXPENSE
ELECTRIC UTILITY - MONTANA

Line No.	Description	MDU Proposed MT[1]	LCG Recommended MT[2]
	(A)	(B)	(C)
1	Fuel Expense		
2	Acct. 501	$13,151,651	$13,518,489
3	Acct. 502 - Reagent	526,675	0
4	Acct. 547	413,125	458,534
5	Total Fuel Expense	14,091,451	13,977,023
6	Purchased Power / Pipeline Charges		
7	Energy	4,986,952	7,948,740
8	Energy - Ft. Peck	475,630	475,630
9	Demand	143,200	143,200
10	Heskett III Pipeline Charges	570,768	570,768
11	Total Purchased Power/Pipeline Charges	6,176,550	9,138,338
12	Other		
13	Deferred Fuel & Purchased Power	0	0
14	Allowances - Acct. 509	0	0
15	Total	$20,268,001	$23,115,360
16	Fuel & Purchased Power -		
17	Sales for Resale	0	0
18	Net Fuel & Purchased Power	$20,268,001	$23,115,360
19	Kwh Sales	805,309,558	805,309,558
20	Base Cost of Fuel	$0.02517	$0.02870

Data Sources:
1. MDU Rule 38.5.157, Statement G, p. 5 of 35.
2. MDU response to Data Request LCG-025, Attachment Pro Forma Fuel PP.

MONTANA LARGE CUSTOMER GROUP
ADJUSTED BASE FUEL AND PURCHASED POWER CHARGE
ELECTRIC UTILITY - MONTANA

Line No.	Description	Montana	Allocation to Primary	Allocation to Secondary	Allocation to Contract
	(A)	(B)	(C)	(D)	(E)
1	Fuel & Purchased Power Costs				
2	Account 501, 502 and 547	$13,977,023	$1,068,216	$8,984,388	$3,924,418
3	Account 555 Energy	7,948,740	607,495	5,109,426	2,231,818
4	Account 555 Energy - Fort Peck	475,630	50,542	425,088	0
5	Account 555 Demand and				
6	547 Pipeline Charges	713,968	67,101	484,679	162,188
7	Total Fuel & Purchased Power	$23,115,360	$1,793,355	$15,003,582	$6,318,424
8	Fuel Costs - Sales for Resale	0	0	0	0
9	Net System Costs	$23,115,360	$1,793,355	$15,003,582	$6,318,424
10	Kwh Retail Sales	805,309,558	61,773,911	514,981,222	228,554,425
11	Cost Per Kwh	$0.02870	$0.02903	$0.02913	$0.02765

Line	Description	Montana	Primary	Secondary	Contract
12	Demand - Class Factor No. 2		9.398338%	67.885240%	22.716422%
13	Demand - Juris Factor No. 15	22.642790%			
14	Energy - Juris Factor No. 16	26.537673%			
15	Energy - Fort Peck	100.000000%	10.626266%	89.373734%	
16	<u>Energy Calculation</u>				
17	MDU Pro Forma	805,309,558	61,773,911	514,981,222	228,554,425
18	Loss Factor		6.92000%	7.74000%	6.26000%
19	Adjust to generation	868,368,584	66,366,471	558,184,719	243,817,394
20	% at generation	100.000000%	7.642661%	64.279700%	28.077639%
21	1-loss factor		0.9308	0.9226	0.9374

Data Source:
MDU Response to Data Request LCG-072, Attachment A.

Direct Testimony of

Kevin C. Higgins

Exhibit KCH-13

**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.

Update 10/22/15:

The Company has become aware that Ottertail Power and Northwestern Energy, partners with Montana-Dakota in the ownership of the Big Stone Station located in South Dakota, have used a probable retirement year of 2046 rather than 2027 as presented in Exhibit EMR-1 Electric Depr. Study. While the inclusion of the environmental project at Big Stone does not appear to support a life extension of 19 years, for accounting consistency Montana-Dakota will adopt the probable retirement year utilized by the other partners.

Please see the File LCG - 003 - DEPR TABLES MDU-Elec in the enclosed CD which shows the depreciation rates that reflect the change in retirement year.

Supplemental information will be submitted in the docket.

Table 1-Plant Site

Montana-Dakota Utilties
Electric Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2014
And Related Annual Depreciation Expense (Plant Site) Under Present and Proposed Rates

Account No. (a)	Location Code (b)	Probable Retirement Date (c)	Description (d)	Original Cost 12/31/14 (e)	Present Rates: Rate % (f)	Present Rates: Annual Accrual (g)	Proposed Rates – Proposed Plant Only Rates: Rate % (h)	Proposed Plant Only Rates: Annual Accrual (i)	Proposed Gross Salv Rates: Rate % (j)	Proposed Gross Salv Rates: Annual Accrual (k)	Proposed COR Rates: Rate % (l)	Proposed COR Rates: Annual Accrual (m)	Total Proposed Rates: Rate % (n)	Total Proposed Rates: Annual Accrual (o)	Net Change Depr. Exp. (p)
			DEPRECIABLE PLANT												
			STEAM PLANT												
			Heskett Generating Station												
311.00	8100	2028	Structures and Improvements	29,286,009.04	5.11%	1,496,515.06	5.49%	1,607,801.90	0.00%	0.00	0.00%	0.00	5.49%	1,607,801.90	111,286.84
312.00	8100	2028	Boiler Plant Equipment	53,007,326.24	3.46%	1,834,053.49	3.33%	1,765,143.96	0.00%	0.00	0.00%	0.00	3.33%	1,765,143.96	(68,909.53)
314.00	8100	2028	Turbogenerator Units	16,946,831.28	3.85%	652,453.00	4.02%	681,262.62	0.00%	0.00	0.00%	0.00	4.02%	681,262.62	28,809.62
315.00	8100	2028	Accessory Electric Equipment	2,168,858.49	1.05%	22,773.01	3.47%	75,259.39	0.00%	0.00	0.00%	0.00	3.47%	75,259.39	52,486.38
316.00	8100	2028	Miscellaneous Power Plant Equipment	7,625,713.21	4.56%	347,732.52	3.70%	282,151.39	0.00%	0.00	0.00%	0.00	3.70%	282,151.39	(65,581.13)
			Total Heskett Generating Station	109,034,738.26	3.99%	4,353,527.08	4.05%	4,411,619.26	0.00%	0.00	0.00%	0.00	4.05%	4,411,619.26	58,092.18
			Lewis & Clark Generating Station												
311.00	8200	2025	Structures and Improvements	4,529,429.02	1.91%	86,512.09	2.04%	92,400.35	0.00%	0.00	0.00%	0.00	2.04%	92,400.35	5,888.26
312.00	8200	2025	Boiler Plant Equipment	24,225,690.93	2.92%	707,390.18	4.11%	995,675.90	0.00%	0.00	0.00%	0.00	4.11%	995,675.90	288,285.72
314.00	8200	2025	Turbogenerator Units	6,292,021.98	0.87%	54,740.59	2.40%	151,008.53	0.00%	0.00	0.00%	0.00	2.40%	151,008.53	96,267.94
315.00	8200	2025	Accessory Electric Equipment	1,003,799.83	1.12%	11,242.56	0.56%	5,621.28	0.00%	0.00	0.00%	0.00	0.56%	5,621.28	(5,621.28)
316.00	8200	2025	Miscellaneous Power Plant Equipment	5,096,633.26	5.34%	272,160.22	4.66%	237,503.11	0.00%	0.00	0.00%	0.00	4.66%	237,503.11	(34,657.11)
			Total Lewis & Clark Generating Station	41,147,575.02	2.75%	1,132,045.64	3.60%	1,482,209.17	0.00%	0.00	0.00%	0.00	3.60%	1,482,209.17	350,163.53
			Coyote Generating Station												
311.00	8300	2041	Structures and Improvements	26,506,987.36	1.42%	376,399.22	0.96%	254,467.08	0.00%	0.00	0.00%	0.00	0.96%	254,467.08	(121,932.14)
312.00	8300	2041	Boiler Plant Equipment	70,892,375.25	1.75%	1,240,616.57	1.34%	949,957.83	0.00%	0.00	0.00%	0.00	1.34%	949,957.83	(290,658.74)
314.00	8300	2041	Turbogenerator Units	19,576,598.97	2.46%	481,584.33	2.41%	471,796.04	0.00%	0.00	0.00%	0.00	2.41%	471,796.04	(9,788.29)
315.00	8300	2041	Accessory Electric Equipment	8,748,738.96	1.76%	153,977.81	1.65%	144,354.19	0.00%	0.00	0.00%	0.00	1.65%	144,354.19	(9,623.62)
316.00	8300	2041	Miscellaneous Power Plant Equipment	3,610,109.70	4.67%	168,592.12	3.84%	138,628.21	0.00%	0.00	0.00%	0.00	3.84%	138,628.21	(29,963.91)
			Total Coyote Generating Station	129,334,810.24	1.87%	2,421,170.05	1.51%	1,959,203.35	0.00%	0.00	0.00%	0.00	1.51%	1,959,203.35	(461,966.70)
			Big Stone Generating Station												
311.00	8610	2046	Structures and Improvements	9,509,529.19	0.75%	71,321.47	0.31%	29,479.54	0.00%	0.00	0.00%	0.00	0.31%	29,479.54	(41,841.93)
312.00	8610	2046	Boiler Plant Equipment	34,242,520.56	2.48%	849,214.51	1.58%	541,031.82	0.00%	0.00	0.00%	0.00	1.58%	541,031.82	(308,182.69)
314.00	8610	2046	Turbogenerator Units	12,161,777.33	3.99%	485,254.92	1.70%	206,750.21	0.00%	0.00	0.00%	0.00	1.70%	206,750.21	(278,504.71)
315.00	8610	2046	Accessory Electric Equipment	4,237,158.97	1.00%	42,371.59	1.21%	51,269.62	0.00%	0.00	0.00%	0.00	1.21%	51,269.62	8,898.03
316.00	8610	2046	Miscellaneous Power Plant Equipment	1,258,777.87	2.09%	26,308.46	2.50%	31,469.45	0.00%	0.00	0.00%	0.00	2.50%	31,469.45	5,160.99
			Total Big Stone Generating Station	61,409,763.92	2.40%	1,474,470.95	1.40%	860,000.64	0.00%	0.00	0.00%	0.00	1.40%	860,000.64	(614,470.31)
			Wygen III Generating Station												
311.00	8720	2060	Structures and Improvements	3,131,340.50	2.00%	62,626.81	2.00%	62,626.81	0.00%	0.00	0.00%	0.00	2.00%	62,626.81	0.00
312.00	8720	2060	Boiler Plant Equipment	29,649,043.71	2.00%	592,980.87	2.65%	785,699.66	0.00%	0.00	0.00%	0.00	2.65%	785,699.66	192,718.79
314.00	8720	2060	Turbogenerator Units	29,068,711.91	2.00%	581,374.24	2.79%	811,017.06	0.00%	0.00	0.00%	0.00	2.79%	811,017.06	229,642.82
315.00	8720	2060	Accessory Electric Equipment	3,588,263.76	2.00%	71,765.28	2.48%	88,988.94	0.00%	0.00	0.00%	0.00	2.48%	88,988.94	17,223.66
316.00	8720	2060	Miscellaneous Power Plant Equipment	9,443.78	2.00%	188.88	3.42%	322.98	0.00%	0.00	0.00%	0.00	3.42%	322.98	134.10
			Total Wygen III Generating Station	65,446,803.66	2.00%	1,308,936.08	2.67%	1,748,655.45	0.00%	0.00	0.00%	0.00	2.67%	1,748,655.45	439,719.37
			Total Depreciable Steam Production Plant	406,373,691.10	2.63%	10,690,149.80	2.57%	10,461,687.87	0.00%	0.00	0.00%	0.00	2.57%	10,461,687.87	(228,461.93)

Table 1-Plant Site

Montana-Dakota Utilties
Electric Division

Summary or Original Cost of Utility Plant in Service as of December 31, 2014
And Related Annual Depreciation Expense (Plant Site) Under Present and Proposed Rates

Account No.	Location Code	Probable Retirement Date	Description	Original Cost 12/31/14	Present Rates Rate %	Present Rates Annual Accrual	Proposed Plant Only Rates Rate %	Proposed Plant Only Rates Annual Accrual	Proposed Gross Salv Rates Rate %	Proposed Gross Salv Rates Annual Accrual	Proposed COR Rates Rate %	Proposed COR Rates Annual Accrual	Total Proposed Rates Rate %	Total Proposed Rates Annual Accrual	Net Change Depr. Exp.
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
			OTHER PRODUCTION PLANT												
			Heskett III												
344.10	8110		Generators	52,131,730.78	2.33%	1,212,375.53	2.48%	1,292,866.92	0.00%	0.00	0.00%	0.00	2.48%	1,292,866.92	80,491.39
346.10	8110		Miscellaneous Power Plant Equipment	1,045,533.32	2.50%	26,138.33	3.40%	35,548.13	0.00%	0.00	0.00%	0.00	3.40%	35,548.13	9,409.80
			Total Heskett III	53,177,264.10	2.33%	1,238,513.86	2.50%	1,328,415.05	0.00%	0.00		0.00	2.50%	1,328,415.05	89,901.19
			Glendive Turbine 1												
341.10	8510		Structures and Improvements	278,336.07	3.42%	9,519.09	8.78%	24,437.91	0.00%	0.00	0.00%	0.00	8.78%	24,437.91	14,918.82
342.00	8510		Fuel Holders, Producers and Accessories	309,452.61	1.09%	3,373.03	9.26%	28,655.31	0.00%	0.00	0.00%	0.00	9.26%	28,655.31	25,282.28
344.10	8510		Generators	6,735,796.33	2.54%	171,089.23	2.74%	184,560.82	0.00%	0.00	0.00%	0.00	2.74%	184,560.82	13,471.59
345.10	8510		Accessory Electric Equipment	466,573.49	3.62%	16,889.96	6.95%	32,426.86	0.00%	0.00	0.00%	0.00	6.95%	32,426.86	15,536.90
346.10	8510		Miscellaneous Power Plant Equipment	126,677.17	2.27%	2,875.57	10.42%	13,199.76	0.00%	0.00	0.00%	0.00	10.42%	13,199.76	10,324.19
			Total Glendive Turbine 1	7,916,835.67	2.57%	203,746.88	3.58%	283,280.66	0.00%	0.00	0.00%	0.00	3.58%	283,280.66	79,533.78
			Glendive Turbine 2												
341.10	8512		Structures and Improvements	15,386.47	3.42%	526.22	2.74%	421.59	0.00%	0.00	0.00%	0.00	2.74%	421.59	(104.63)
342.00	8512		Fuel Holders, Producers and Accessories	2,055,650.83	1.09%	22,406.59	2.81%	57,763.79	0.00%	0.00	0.00%	0.00	2.81%	57,763.79	35,357.20
344.10	8512		Generators	17,968,383.93	1.69%	303,665.69	2.57%	461,787.47	0.00%	0.00	0.00%	0.00	2.57%	461,787.47	158,121.78
346.10	8512		Miscellaneous Power Plant Equipment	12,613.98	2.27%	286.34	4.15%	523.48	0.00%	0.00	0.00%	0.00	4.15%	523.48	237.14
			Total Glendrive Turbine 2	20,052,035.21	1.63%	326,884.84	2.60%	520,496.33	0.00%	0.00	0.00%	0.00	2.60%	520,496.33	193,611.49
			Miles City Turbine												
341.10	8520		Structures and Improvements	207,622.13	3.53%	7,329.06	15.97%	33,157.25	0.00%	0.00	0.00%	0.00	15.97%	33,157.25	25,828.19
342.00	8520		Fuel Holders, Producers and Accessories	200,837.28	2.33%	4,679.51	10.69%	21,469.51	0.00%	0.00	0.00%	0.00	10.69%	21,469.51	16,790.00
344.10	8520		Generators	2,668,314.37	1.00%	26,683.14	4.11%	109,667.72	0.00%	0.00	0.00%	0.00	4.11%	109,667.72	82,984.58
345.10	8520		Accessory Electric Equipment	346,031.49	3.78%	13,079.99	11.41%	39,482.19	0.00%	0.00	0.00%	0.00	11.41%	39,482.19	26,402.20
346.10	8520		Miscellaneous Power Plant Equipment	17,989.02	2.50%	449.73	11.08%	1,993.18	0.00%	0.00	0.00%	0.00	11.08%	1,993.18	1,543.45
			Total Miles City Turbine	3,440,794.29	1.52%	52,221.43	5.98%	205,769.85	0.00%	0.00	0.00%	0.00	5.98%	205,769.85	153,548.42
			Portable Generators												
341.10	8550		Structures and Improvements	166,110.58	3.43%	5,697.59	2.55%	4,235.82	0.00%	0.00	0.00%	0.00	2.55%	4,235.82	(1,461.77)
342.00	8550		Fuel Holders, Producers and Accessories	156,064.84	3.19%	4,978.47	2.60%	4,057.69	0.00%	0.00	0.00%	0.00	2.60%	4,057.69	(920.78)
344.10	8550		Generators	1,397,371.30	1.97%	27,528.21	2.99%	41,781.40	0.00%	0.00	0.00%	0.00	2.99%	41,781.40	14,253.19
345.10	8550		Accessory Electric Equipment	572,984.71	4.75%	27,216.77	3.04%	17,418.74	0.00%	0.00	0.00%	0.00	3.04%	17,418.74	(9,798.03)
			Total Portable Generators	2,292,531.43	2.85%	65,421.04	2.94%	67,493.65	0.00%	0.00	0.00%	0.00	2.94%	67,493.65	2,072.61
			Diamond Willow Wind Farm												
341.20	8560		Structures and Improvements	3,363,993.85	5.09%	171,365.36	3.44%	115,721.39	0.00%	0.00	0.00%	0.00	3.44%	115,721.39	(55,643.97)
344.20	8560		Generators	49,146,139.62	5.10%	2,504,858.00	5.88%	2,889,793.01	0.00%	0.00	0.00%	0.00	5.88%	2,889,793.01	384,935.01
345.20	8560		Accessory Electric Equipment	8,293,797.94	5.10%	423,152.80	5.78%	479,381.52	0.00%	0.00	0.00%	0.00	5.78%	479,381.52	56,228.72
346.20	8560		Miscellaneous Power Plant Equipment	55,790.93	5.17%	2,884.39	5.88%	3,280.51	0.00%	0.00	0.00%	0.00	5.88%	3,280.51	396.12
			Total Diamond Willow	60,859,722.34	5.10%	3,102,260.55	5.73%	3,488,176.43	0.00%	0.00	0.00%	0.00	5.73%	3,488,176.43	385,915.88
			Ormat Generation Facility												
344.10	8570		Generators	15,184,122.44	5.00%	759,206.12	5.21%	791,092.78	0.00%	0.00	0.00%	0.00	5.21%	791,092.78	31,886.66
			Total Ormat Generation Facility	15,184,122.44	5.00%	759,206.12	5.21%	791,092.78	0.00%	0.00	0.00%	0.00	5.21%	791,092.78	31,886.66
			Cedar Hills Wind Farm												
341.20	8580		Structures and Improvements	2,799,226.32	5.00%	139,961.32	8.00%	223,938.11	0.00%	0.00	0.00%	0.00	8.00%	223,938.11	83,976.79
344.20	8580		Generators	35,054,454.74	5.00%	1,752,722.74	5.03%	1,763,239.07	0.00%	0.00	0.00%	0.00	5.03%	1,763,239.07	10,516.33
345.20	8580		Accessory Electric Equipment	5,967,801.82	5.00%	298,390.09	5.88%	350,906.75	0.00%	0.00	0.00%	0.00	5.88%	350,906.75	52,516.66
346.20	8580		Miscellaneous Power Plant Equipment	63,308.47	5.00%	3,165.42	5.90%	3,735.20	0.00%	0.00	0.00%	0.00	5.90%	3,735.20	569.78
			Total Cedar Hills	43,884,791.35	5.00%	2,194,239.57	5.34%	2,341,819.13	0.00%	0.00	0.00%	0.00	5.34%	2,341,819.13	147,579.56
			Total Depreciable Other Production Plant	206,808,096.83	3.84%	7,942,494.29	4.36%	9,026,543.88	0.00%	0.00	0.00%	0.00	4.36%	9,026,543.88	1,084,049.59

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
SECOND DATA REQUEST
DATED OCTOBER 1, 2015
DOCKET NO. D2015.6.51

LCG-023 RE: New Large Generation Projects

For each of the new large generation projects listed below, please provide the exact actual or anticipated post-testing commercial in-service date for the project.

a. **AQCS Project – Big Stone Station.**
b. **MATS Compliance – Lewis & Clark.**
c. **RICE Units – Lewis & Clark.**
d. **Thunder Spirit Wind Farm.**

Response:

a. AQCS Project – Big Stone Station:
Anticipated post-testing commercial in-service date: 12/1/2015

b. MATS Compliance – Lewis & Clark:
Anticipated post-testing commercial in-service date: 11/30/2015

c. RICE Units – Lewis & Clark:
Anticipated post-testing commercial in-service date: 11/30/2015

d. Thunder Spirit Wind Farm:
Anticipated post-testing commercial in-service date: 12/31/2015

**MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
SECOND DATA REQUEST
DATED OCTOBER 1, 2015
DOCKET NO. D2015.6.51**

LCG-025 RE: Fuel and Purchased Power

Please prepare a pro forma 2014 fuel and purchase power report using the exact in-service dates provided in the response to the question #7 above. Please provide a monthly summary (both dollars and kWhs) in electronic format, preferably Excel, with formulas intact.

Response:

Please attached Excel file - 'LCG-025 Pro forma Fuel PP'.

No.	Station	Generation	Capacity Factor	Units Started	Fuel Offtake	Average Heat Rate	Hours of Operation	Fuel Price	Fuel Cost	Start & Shutdown Cost	FO&M Cost	VO&M Cost	Production Cost	Total Cost	Total Cost
#	Name	GWh	%	#	1000 MMBTU	BTU/kWh	hrs	$/MMBTU	$000	$000	$000	$000	$/MWh	$/MWh	$000
1	Big Stone I	582.004	61.23	8	6202.4	10657	7992	2.61	16173.57	0.00	2791.42	991.51	29.49	34.29	19956.50
2	Coyote	687.988	72.99	11	7979.8	11599	7848	1.72	13739.70	0.00	2837.09	1982.03	22.85	26.98	18558.82
3	Heskett 1	96.152	42.05	9	1498.2	15582	7104	2.01	3010.10	9.00	1778.12	673.64	38.31	56.90	5470.87
4	Heskett 2	404.400	63.15	4	5217.3	12901	8088	2.01	10495.05	12.00	4213.47	2639.15	32.48	42.93	17359.67
5	Lewis & Clark	297.473	64.93	4	3876.6	13032	7728	1.94	7522.33	12.00	3126.28	1284.42	29.61	40.15	11945.03
6	Lewis & Clark pk	0.000	0.00	136	0.0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Glendive CT 1	6.378	2.14	2	105.9	16601	538	3.31	350.81	4.53	202.93	16.42	57.57	90.10	574.69
8	Glendive CT 2	7.527	2.13	3	96.5	12822	558	3.31	319.73	6.83	407.58	19.38	45.05	100.10	753.52
9	Glendive Diesel	0.000	0.00	10	0.0	0	0	0.00	0.00	0.00	59.66	0.00	0.00	0.00	59.66
10	Heskett 3 CT	15.292	1.98	10	237.7	15542	546	3.37	800.35	37.50	432.53	38.23	54.84	85.58	1308.62
11	Lewis & Clark 2 CT	0.000	0.00	0	0.0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	Miles City CT	0.000	0.00	0	0.0	0	0	0.00	0.00	0.00	249.95	0.00	0.00	0.00	249.95
13	Demand Response P	0.000	0.00	52	0.0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	Ft. Peck Capacity	14.305	79.66	0	14.3	1000	8760	33.25	475.63	0.00	0.00	0.00	33.25	33.25	475.63
15	Heskett 3 Firm	0.000	0	52	0	0	0	0	0.00	0.00	365.00	0.00	0.00	0.00	365.00
16	MISO Sales	0.000	0.00						0.00					0.00	0.00
17	MISO Purchases	993.757	32.41	5	993.8	1000	7861	30.14	29952.66	0.00	0.00	0.00	30.14	30.14	29952.66
18	ND State Capitol	0.000	0	0	0	0	0	0	0.00	0.00	127.50	0.00	0.00	0.00	127.50
19	WEPCO Purchase	0.000	0	52	0	0	0	0	0.00	0.00	4176.00	0.00	0.00	0.00	4176.00
20	Williston Water Plan	0.000	0.00	0	0.0	0	0	0.00	0.00	0.00	120.00	0.00	0.00	0.00	120.00
21	Cedar Hills	64.458	37.48442	2444	0	0	8094	0	0.00	0.00	400.11	0.00	0.00	6.21	400.11
22	Diamond Willow	99.207	37.50017	3760	0	0	8094	0	0.00	0.00	688.72	0.00	0.00	6.94	688.72
23	Glen Ullin Stat6	36.142	55.01069	2	36.14202161	1000	8608	7.11	256.97	0.00	401.31	0.00	7.11	18.21	658.28
24	Thunder Spirit	0.000	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total:	3305.083							83096.90	81.85	22377.65	7644.79	27.46	34.25	113201.19

Time of Day Marginal Cost Summary

No.	Timeslice	Total Hours	% of Hrs	Average Marg Cost
1	Summer Off Peak	2232	25.5%	$27.50
2	Summer On Peak	696	7.9%	$27.97
3	Winter Off Peak	5832	66.6%	$32.44
	Total:	8760	100%	$30.83

Fuel Use Report

No.	Fuel	Generation	Price	Cost	Offtake	Transport Cost	Units Used	Production Cost	Total Cost
#	Name	GWH	$/MMBTU	$000	1000 MMBTU	$000	#	$/MMBTU	$000
1	Bigstone Subbit	580.549	2.56	15830.22	6186.9	40.36	371631.87	2.57	15870.58
2	Coyote Lignite	686.268	1.67	13297.96	7959.8	31.56	569291.80	1.67	13329.53
3	Heskett1 Lignite	96.152	2.01	3010.10	1498.2	160.57	106589.21	2.12	3170.67
4	Heskett2 Lignite	404.036	2.01	10472.72	5212.6	558.67	370844.47	2.12	11031.39
5	L&C Lignite	296.670	1.94	7489.47	3866.1	153.18	295439.00	1.98	7642.65
6	Heskett2 Gas	0.364	4.76	22.33	4.7	0.00	4268.69	4.76	22.33
7	L&C Gas	0.803	3.14	32.86	10.5	0.00	8664.54	3.14	32.86
8	L&C Gas	0.000	3.14	0.00	0.0	0.00	0.00	0.00	0.00
9	Glendive1 Gas	6.378	3.31	350.81	105.9	0.00	95569.92	3.31	350.81
10	Glendive2 Gas	7.527	3.31	319.73	96.5	0.00	87104.46	3.31	319.73
11	Heskett3 Gas	15.292	3.37	800.35	237.7	0.00	216060.99	3.37	800.35
12	Heskett3 Gas	0.000	3.37	0.00	0.0	0.00	0.00	0.00	0.00
13	MilesCity Gas	0.000	3.52	0.00	0.0	0.00	0.00	0.00	0.00
14	BigStone Oil	1.455	22.14	343.35	15.5	0.00	110757.74	22.14	343.35
15	Coyote Oil	1.720	22.14	441.74	19.9	0.00	142496.20	22.14	441.74
16	Glendive Diesel	0.000	22.14	0.00	0.0	0.00	0.00	0.00	0.00

**MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
SECOND DATA REQUEST
DATED OCTOBER 1, 2015
DOCKET NO. D2015.6.51**

LCG-032 RE: Load Forcast

Please refer to Exhibit No. DJN1 Demand and Energy 1985 to 2014.

a. **Please provide the projected peak customer load and annual energy requirements for both Montana and the integrated system for 2015 in the same format as the aforementioned exhibit. Please provide this information in Excel format with any formulas intact.**

b. **Given that MDU has forecasted the peak customer load and energy requirements for 2015 and beyond in its IRP, please explain why this forecasted load information has not been incorporated into the pro forma revenue calculation in the rate case.**

Response:

a. Please see Attachment A for select pages from the Company's 2015 IRP Volume II. Attachment A Page 1 shows the projected 2015 summer Integrated System peak of 624.5 MW and the projected 2016 winter peak of 603.7 MW. Total energy requirements are 3,563,732 MWh.

   Attachment A Page 2 shows the projected 2015 Montana MWh sales and peak demand.

b. The Pro Forma adjustments made to volumes reflect known and measureable changes for 2015 in accordance with ARM 38.5.106.

Montana-Dakota Utilities Co.
Historical and Forecasted Energy and Demand
Integrated System
Reflecting Demand-Side Management Programs from 2013 IRP
Calendar Month Basis

	Total Energy Requirements (net of DSM and EE)		Summer Peak - MW				Winter Peak 2/				Demand Response	
Year	MWh	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Rate 38/39 Interrupt Loads	Commercial Demand Response
2004	2,204,012				458.4				383.9			
2005	2,327,117	5.59%			459.1	0.15%			387.2	0.86%		
2006	2,397,793	3.04%			485.5	5.75%			397.2	2.58%		
2007	2,510,540	4.70%			525.6	8.26%			407.3	2.54%		
2008	2,596,990	3.44%			476.6	-9.32%			455.0	11.71%		
2009	2,593,368	-0.14%			473.8	-0.59%			459.6	1.01%		
2010	2,718,192	4.81%			502.5	6.06%			457.8	-0.39%		
2011	2,776,082	2.13%			535.8	6.63%			510.8	11.58%		
2012	2,919,752	5.18%			573.6	7.05%			516.2	1.06%		
2013	3,115,064	6.69%			546.9	-4.65%			582.1	12.77%		
2014	3,250,683	4.35%			533.0	-2.54%			not yet available			
2015	3,563,732	9.63%	626.0	1.5	624.5	17.17%	605.2	1.5	603.7		13.4	10.0
2016	3,809,892	6.91%	656.2	1.5	654.7	4.84%	634.3	1.5	632.8	4.82%	15.4	12.5
2017	4,044,774	6.17%	685.2	1.5	683.7	4.43%	652.4	1.5	650.9	2.86%	15.4	15.0
2018	4,220,333	4.34%	707.4	1.5	705.9	3.25%	664.5	1.5	663.0	1.86%	15.4	15.0
2019	4,366,313	3.46%	726.3	1.5	724.8	2.68%	676.6	1.5	675.1	1.83%	15.4	15.0
2020	4,464,924	2.26%	739.8	1.5	738.3	1.86%	688.0	1.5	686.5	1.69%	15.4	15.0
2021	4,565,434	2.25%	753.5	1.5	752.0	1.86%	699.2	1.5	697.7	1.63%	15.4	15.0
2022	4,659,237	2.05%	766.4	1.5	764.9	1.72%	709.3	1.5	707.8	1.45%	15.4	15.0
2023	4,738,979	1.71%	777.8	1.5	776.3	1.49%	719.2	1.5	717.7	1.40%	15.4	15.0
2024	4,818,606	1.68%	789.1	1.5	787.6	1.46%	728.6	1.5	727.1	1.31%	15.4	15.0
2025	4,898,425	1.66%	800.5	1.5	799.0	1.45%	738.2	1.5	736.7	1.32%	15.4	15.0
2026	4,978,277	1.63%	811.9	1.5	810.4	1.43%	747.4	1.5	745.9	1.25%	15.4	15.0
2027	5,059,454	1.63%	823.4	1.5	821.9	1.42%	756.6	1.5	755.1	1.23%	15.4	15.0
2028	5,139,170	1.58%	834.8	1.5	833.3	1.39%	765.3	1.5	763.8	1.15%	15.4	15.0
2029	5,220,318	1.58%	846.3	1.5	844.8	1.38%	774.0	1.5	772.5	1.14%	15.4	15.0
2030	5,302,866	1.58%	858.0	1.5	856.5	1.38%	782.8	1.5	781.3	1.14%	15.4	15.0
2031	5,386,977	1.59%	869.8	1.5	868.3	1.38%	791.8	1.5	790.3	1.15%	15.4	15.0
2032	5,472,577	1.59%	881.9	1.5	880.4	1.39%	800.6	1.5	799.1	1.11%	15.4	15.0
2033	5,558,146	1.56%	893.9	1.5	892.4	1.36%	809.8	1.5	808.3	1.15%	15.4	15.0
2034	5,645,254	1.57%	906.1	1.5	904.6	1.37%	819.1	1.5	817.6	1.15%	15.4	15.0

1/ Historical demand reported is system actual demand.
2/ Winter Peak is for Nov-Dec of current year and Jan-Apr of following year.

MONTHLY FORECASTS
SALES AND ENERGY (MWH)
PEAK DEMAND (MW)

MONTANA YEAR 2015

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
Use per Residential Customer - kWh	970.7	952.3	788.4	697.0	700.7	724.4	1,060.7	866.2	792.1	663.2	841.7	990.7	10,048.8
# of Residential Customers	20,279	20,286	20,317	20,298	20,307	20,339	20,366	20,379	20,402	20,439	20,475	20,505	20,366
Total Residential Sales - MWh	19,684	19,319	16,018	14,148	14,230	14,733	21,602	17,653	16,161	13,556	17,234	20,315	204,653
Use per Small Comm & Ind Customer - kWh	2,415.5	2,431.6	2,136.8	1,973.4	2,074.1	1,959.7	2,679.8	2,302.3	2,258.4	1,937.2	2,171.7	2,439.1	26,780.0
# of Small Comm & Ind Customers	5,232	5,223	5,226	5,263	5,293	5,332	5,346	5,356	5,348	5,318	5,307	5,308	5,296
Total Small Comm & Ind Sales - MWh	12,638	12,700	11,167	10,386	10,978	10,449	14,326	12,331	12,078	10,302	11,525	12,947	141,827
Large Comm & Ind Sales	40,124	38,659	37,958	39,784	38,904	37,059	39,962	37,360	40,936	41,931	41,206	47,293	481,176
Total Sales (Residential, SC&I and LC&I)	72,446	70,678	65,143	64,318	64,112	62,241	75,890	67,344	69,175	65,789	69,965	80,555	827,656
Other Public Sales	505	581	472	502	589	640	918	739	730	492	510	544	7,222
Street & Highway Lighting Sales	623	566	591	588	589	557	583	581	574	605	587	584	7,028
Interdepartmental Sales	17	18	14	14	13	12	15	12	14	12	15	17	173
Total Billed Sales - MWh	73,591	71,843	66,220	65,422	65,303	63,450	77,406	68,676	70,493	66,898	71,077	81,700	842,079
Company Use	35	33	31	29	28	26	33	29	27	25	29	33	358
Total Energy	73,626	71,876	66,251	65,451	65,331	63,476	77,439	68,705	70,520	66,923	71,106	81,733	842,437
Total Requirements (Energy + Losses)	79,836	77,938	71,839	70,971	70,841	68,830	83,970	74,500	76,468	72,567	77,103	88,626	913,489
# of Large Comm & Ind Customers	261	258	259	262	263	259	261	260	260	260	259	259	260
# of Other Public Customers	101	101	101	102	103	103	104	104	103	102	100	101	102
# of Street & Highway Lighting Customers	35	35	35	35	35	35	35	35	35	35	35	35	35
Peak Demand Net of Energy Efficiency Progs	138.3	132.6	119.5	103.0	107.1	145.6	160.1	152.8	132.4	114.7	132.8	154.7	160.1

**MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
SECOND DATA REQUEST
DATED OCTOBER 1, 2015
DOCKET NO. D2015.6.51**

LCG-033 RE: Sales and Energy Forecast

Please refer to Rule 38.5.164, p. 5 of 8.

a. Please modify this schedule to reflect the Montana forecasts billing determinants for the calendar year 2015, consistent with the most recent load forecast (i.e. the 2015 IRP or more recent, if available). Please provide this information in Excel format with formulas intact.

b. Please explain the discrepancy of nearly 40 million kWh between Montana's total kWh consumption provided in the 2014 pro forma forecast in the referenced exhibit and Montana's total kWh consumption forecasted in MDU's 2015 IRP. Why were 2015 IRP load projections (or more recent, if available) not incorporated in this rate case?

c. Has MDU modified its Montana 2014 test period pro forma sales and energy forecast since filing its case? If so, please provide the updated information.

d. Please provide MDU's monthly actual kWh sales and revenues for Montana by rate schedule for 2014 and year-to-date 2015.

Response:

a. Please see Response LCG-032b.

b. The Company did not use the 2015 forecasted sales volumes from the IRP in accordance with ARM 38.5.106.

   In addition, as noted in Response No. PSC-022, the Company has updated its load forecast. Please see Attachment A for an updated forecast for Montana showing a 2015 forecasted sales volumes of 815,792 MWh, a decrease of 25,955 MWh from the Company's 2015 IRP forecast. The Company's actual sales volumes for the twelve months ended August 31, 2015 are 810,420 MWhs, indicating the updated forecast is strong.

c. No, as noted above, the forecast is not appropriate as this reflects growth. The actual sales volumes are within .6% of the pro forma sales volumes reflected in the case.

**MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
SECOND DATA REQUEST
DATED OCTOBER 1, 2015
DOCKET NO. D2015.6.51**

d. Please see Response No. MCC-007 Attachment A for the actual monthly Kwh sales and Response No. LCG-033 Attachment B for the monthly revenues.

Montana-Dakota Utilities Co.
Historical and Forecasted Annual Sales by Sector
Montana
Billing Month Basis
Reflecting Demand-Side Programs

	Residential		Small C&I		Large C&I		Street Lighting		Miscellaneous		Total Sales	
YEAR	Sales (MWh)	% Change	Sales (MWh)	% Change	Sales (MWh)	% Change	Sales (MWh)	% Change	Sales (MWh)	% Change	Sales (MWh)	% Change
2004	141,249		98,151		348,097		7,250		7,357		602,104	
2005	150,706	6.70%	102,046	3.97%	364,489	4.71%	7,232	-0.25%	7,131	-3.07%	631,604	4.90%
2006	157,206	4.31%	104,214	2.12%	368,666	1.15%	7,203	-0.40%	7,621	6.87%	644,910	2.11%
2007	162,186	3.17%	109,101	4.69%	385,230	4.49%	7,187	-0.22%	7,456	-2.17%	671,160	4.07%
2008	162,182	0.00%	108,595	-0.46%	408,686	6.09%	7,244	0.79%	7,637	2.43%	694,344	3.45%
2009	167,421	3.23%	110,380	1.64%	407,647	-0.25%	7,244	0.00%	7,701	0.84%	700,393	0.87%
2010	171,661	2.53%	109,188	-1.08%	415,946	2.04%	7,203	-0.57%	7,511	-2.47%	711,509	1.59%
2011	185,153	7.86%	119,643	9.58%	427,887	2.87%	7,089	-1.58%	7,789	3.70%	747,561	5.07%
2012	187,635	1.34%	132,714	10.93%	420,459	-1.74%	7,106	0.24%	8,134	4.43%	756,048	1.14%
2013	194,907	3.88%	128,003	-3.55%	438,918	4.39%	7,028	-1.10%	7,742	-4.82%	776,598	2.72%
2014	200,088	2.66%	137,799	7.65%	451,687	2.91%	7,108	1.14%	7,900	2.04%	804,582	3.60%
2015	203,615	1.76%	139,931	1.55%	457,222	1.23%	7,108	0.00%	7,916	0.20%	815,792	1.39%
2016	207,150	1.74%	144,846	3.51%	468,919	2.56%	7,108	0.00%	7,932	0.20%	835,955	2.47%
2017	210,591	1.66%	149,952	3.53%	473,630	1.00%	7,108	0.00%	7,948	0.20%	849,229	1.59%
2018	214,048	1.64%	155,030	3.39%	478,400	1.01%	7,108	0.00%	7,963	0.19%	862,549	1.57%
2019	217,519	1.62%	160,386	3.45%	482,578	0.87%	7,108	0.00%	7,979	0.20%	875,570	1.51%
2020	221,007	1.60%	165,874	3.42%	487,471	1.01%	7,108	0.00%	7,995	0.20%	889,455	1.59%
2021	224,508	1.58%	171,495	3.39%	492,407	1.01%	7,108	0.00%	8,011	0.20%	903,529	1.58%
2022	227,574	1.37%	177,065	3.25%	496,701	0.87%	7,108	0.00%	8,027	0.20%	916,475	1.43%
2023	230,641	1.35%	182,947	3.32%	501,717	1.01%	7,108	0.00%	8,043	0.20%	930,456	1.53%
2024	233,196	1.11%	188,416	2.99%	506,778	1.01%	7,108	0.00%	8,058	0.19%	943,556	1.41%
2025	235,751	1.10%	194,009	2.97%	511,884	1.01%	7,108	0.00%	8,074	0.20%	956,826	1.41%
2026	237,795	0.87%	199,144	2.65%	517,037	1.01%	7,108	0.00%	8,090	0.20%	969,174	1.29%
2027	239,839	0.86%	204,388	2.63%	522,237	1.01%	7,108	0.00%	8,106	0.20%	981,678	1.29%
2028	240,862	0.43%	208,546	2.03%	527,484	1.00%	7,108	0.00%	8,122	0.20%	992,122	1.06%
2029	241,884	0.42%	212,774	2.03%	532,780	1.00%	7,108	0.00%	8,138	0.20%	1,002,684	1.06%
2030	242,906	0.42%	217,066	2.02%	538,126	1.00%	7,108	0.00%	8,153	0.18%	1,013,359	1.06%
2031	243,928	0.42%	221,430	2.01%	543,522	1.00%	7,108	0.00%	8,169	0.20%	1,024,157	1.07%
2032	244,950	0.42%	225,866	2.00%	548,969	1.00%	7,108	0.00%	8,185	0.20%	1,035,078	1.07%
2033	245,461	0.21%	229,729	1.71%	554,469	1.00%	7,108	0.00%	8,201	0.20%	1,044,968	0.96%
2034	245,972	0.21%	233,659	1.71%	560,021	1.00%	7,108	0.00%	8,217	0.20%	1,054,977	0.96%
2035	246,483	0.21%	237,659	1.71%	565,652	1.01%	7,108	0.00%	8,232	0.18%	1,065,134	0.96%

	Residential	Small C&I	Large C&I	Street Lighting	Miscellaneous	Total Sales
2004-2014 Average Yearly Growth (10 Years History)	3.35%	3.25%	2.45%	-0.26%	0.87%	2.76%
2009-2014 Average Yearly Growth (5 Years History)	3.74%	4.95%	1.89%	-0.47%	0.75%	2.80%
2015-2020 Average Yearly Growth (5 Years)	1.65%	3.46%	1.20%	0.00%	0.20%	1.69%
2015-2025 Average Yearly Growth (10 Years)	1.50%	3.34%	1.04%	0.00%	0.20%	1.57%
2015-2035 Average Yearly Growth (20 Years)	0.96%	2.71%	1.01%	0.00%	0.20%	1.32%

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - MONTANA
Revenues by Rate and Month

Year	Month	Rate 10	Rate 20 Primary	Rate 20 Secondary	Rate 25	Rate 30 Primary	Rate 30 Secondary	Rate 31 Primary	Rate 31 Secondary	Rate 32	Rate 35	Rate 41 Municipal Owned Lighting	Rate 41 Company Owned Lighting	Rate 48	Rate 52	Total
2014	January	1,924,226	504	975,547	2,309	317,103	1,098,735	60,348	7,284	9,770	1,022,122	6,425	44,937	39,246	49,342	5,557,898
	February	1,472,385	468	803,904	1,491	301,815	915,511	66,088	8,140	7,440	896,783	5,093	36,340	32,383	12,763	4,560,604
	March	1,595,649	453	860,740	1,480	228,247	964,909	73,022	7,562	7,485	1,001,487	5,329	39,675	38,168	29,811	4,854,017
	April	1,342,839	420	796,026	1,648	193,337	908,619	74,293	6,905	5,520	1,005,178	5,532	41,947	37,378	30,192	4,449,834
	May	1,064,980	314	690,126	3,357	174,408	859,915	73,649	6,160	4,077	952,511	4,988	39,941	34,906	29,280	3,938,612
	June	1,133,354	368	753,489	9,870	174,917	938,132	95,979	3,089	2,415	1,032,124	4,853	40,266	38,581	30,572	4,258,009
	July	1,459,636	507	927,443	50,806	178,166	910,440	103,473	3,128	1,890	973,435	4,848	42,450	48,618	31,357	4,736,197
	August	1,730,191	791	990,864	59,212	196,816	923,832	104,871	3,005	1,876	993,131	4,185	38,373	52,801	28,951	5,128,897
	September	1,502,473	651	946,589	45,636	189,585	929,948	120,908	3,311	3,023	1,022,763	4,320	39,522	43,745	29,284	4,881,758
	October	1,255,369	593	854,353	17,199	256,832	933,403	108,225	3,442	5,481	1,036,975	4,630	42,135	38,262	31,758	4,588,655
	November	943,311	436	614,436	4,005	279,481	770,540	83,607	5,459	4,194	828,206	3,968	35,724	27,275	25,849	3,626,491
	December	1,571,860	942	838,061	2,193	349,547	978,383	91,337	6,542	9,575	1,024,426	4,525	41,483	34,789	35,963	4,989,626
	Total	16,996,273	6,447	10,051,578	199,206	2,840,254	11,132,367	1,055,800	64,027	62,746	11,789,141	58,696	482,793	466,152	365,122	
2015	January	1,678,837	709	868,753	2,257	375,049	985,649	74,731	6,821	11,143	1,111,590	4,940	42,720	36,532	35,663	5,235,394
	February	1,402,608	595	763,018	1,961	326,553	938,757	71,845	7,434	8,437	988,233	4,300	37,203	33,296	29,280	4,613,520
	March	1,488,303	658	816,607	1,854	266,801	1,000,461	73,481	8,630	10,090	1,032,426	4,689	42,159	37,654	26,649	4,810,462
	April	1,171,591	549	714,682	4,718	279,572	928,960	71,366	7,305	6,193	1,025,224	4,435	41,677	33,872	30,217	4,320,361
	May	918,261	335	593,660	25,028	291,585	842,818	61,746	5,500	3,581	979,690	3,789	37,706	34,635	27,657	3,825,991
	June	1,090,384	485	713,530	32,011	282,666	924,427	99,459	5,699	3,412	1,139,562	4,032	42,151	39,371	37,034	4,414,223
	July	1,654,234	361	937,459	53,959	309,035	987,273	118,688	6,141	2,266	1,133,267	3,825	41,244	52,626	31,206	5,331,584
	August	1,750,120	256	938,762	89,451	265,100	937,669	112,380	6,890	2,038	1,015,399	3,551	37,738	49,740	28,262	5,237,356
	September	1,556,200	237	898,568	77,017	253,005	978,407	101,596	8,353	2,004	1,035,803	3,979	39,295	47,123	30,138	5,031,725
	Total	12,710,538	4,185	7,245,039	288,256	2,649,366	8,524,421	785,292	62,773	49,164	9,461,194	37,540	361,893	364,849	276,106	

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
THIRD DATA REQUEST
DATED OCTOBER 12, 2015
DOCKET NO. D2015.6.51

LCG-044 RE: Major Overhaul of MDU Facilities/MCC-036

Please refer to the Company's response to MCC Data Request 36.

a. For each year 2007 through 2014 listed in this response, please provide the actual major overhaul expenses incurred for each applicable generation unit, by FERC account, on a Total Company and Montana jurisdictional basis, in Excel format with formulas intact.

b. For 2015, please provide the actual major overhaul expense incurred to-date for Big Stone and Lewis & Clark, separately, by FERC account, on a Total Company and Montana jurisdictional basis, in Excel format with formulas intact.

c. For 2015, please provide the most recent estimate of 2015 major overhaul expense for Big Stone and Lewis & Clark, separately, by FERC account, on a Total Company and Montana jurisdictional basis, in Excel format with formulas intact.

Response:

a. Expenses are not specifically tracked for major overhauls. However, the increase in costs related to major overhauls can be identified on the attached Excel file labeled Response No. LCG-044 Attachment A Major Overhaul Costs. The highlighted areas reflect major overhauls.

b. See Response a. The 2015 outage for Lewis & Clark was scheduled early in the year. As a result of preparations for the outage and long lead times for supplies and parts, 2014 costs reflect some increase related to the 2015 outage.

c. See the attached Excel file labeled Response No. LCG-044 Attachment B Big Stone 2015 Estimate. Overhaul expenses for Lewis & Clark are not budgeted by FERC Account.

MONTANA-DAKOTA UTILITIES CO.

RESPONSE TO DATA REQUEST: LCG-044

		Total Company								
	Coyote Station - 25% Share	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	
849C.5260.15100	Maint. Supervision & Eng.	$ 150,563.78	$ 153,831.39	$ 156,767.32	$ 178,334.90	$ 165,274.34	$ 193,826.06	$ 151,389.54	$ 196,129.54	
849C.5260.15110	Maintenance of Structures	100,267.34	126,918.85	109,887.84	118,862.41	122,627.44	134,121.79	216,460.26	194,016.80	
849C.5260.15124	Maintenance of Boilers	1,118,605.84	1,425,787.64	1,703,655.66	1,222,043.36	1,532,563.60	1,971,196.52	1,369,869.43	1,486,765.29	
849C.5260.15131	Maint. of Turbine & Gen.	193,769.64	166,185.82	631,973.10	232,823.81	189,464.56	609,651.56	266,079.67	185,971.52	
849C.5260.15140	Maint. Of Misc. Steam Plant	164,655.85	190,181.53	276,754.74	245,392.28	227,350.72	291,572.58	215,068.42	280,335.43	
	Total	$ 1,727,862.45	$ 2,062,905.23	$ 2,879,038.66	$ 1,997,456.76	$ 2,237,280.66	$ 3,200,368.51	$ 2,218,867.32	$ 2,343,218.58	
	Year-to-year change		$ 335,042.78	$ 816,133.43	$ (881,581.90)	$ 239,823.90	$ 963,087.85	$ (981,501.19)	$ 124,351.26	
	Big Stone Station	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**YTD 9/30/2015**
861000.5250.15100	Maint. Supervision & Eng.	$ 117,458.92	$ 115,888.44	$ 120,935.98	$ 122,130.04	$ 134,816.13	$ 151,289.09	$ 148,341.79	$ 135,488.85	$ 104,906.16
861000.5250.15110	Maintenance of Structures	113,744.70	102,202.76	85,862.54	86,303.48	90,949.35	123,035.32	138,215.72	128,433.65	$ 226,717.38
861000.5250.15123	Maintenance of Boilers	1,033,796.98	811,950.58	790,503.75	815,921.45	1,411,686.69	1,010,462.28	1,000,820.92	1,049,826.09	$ 1,382,129.85
861000.5250.15131	Maint. of Turbine & Gen.	125,246.24	266,253.05	16,198.78	132,073.88	306,791.51	176,553.25	225,481.06	281,772.19	$ 1,218,275.77
861000.5250.15140	Maint. Of Misc. Steam Plant	115,714.55	116,218.51	106,273.48	106,595.53	131,678.47	132,635.78	157,415.53	183,330.37	$ 138,338.56
	Total	$ 1,505,961.39	$ 1,412,513.34	$ 1,119,774.53	$ 1,263,024.38	$ 2,075,922.15	$ 1,593,975.72	$ 1,670,275.02	$ 1,778,851.15	$ 3,070,367.72
	Year-to-year change		$ (93,448.05)	$ (292,738.81)	$ 143,249.85	$ 812,897.77	$ (481,946.43)	$ 76,299.30	$ 108,576.13	$ 1,291,516.57
	Heskett	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	
15100	Maint. Supervision & Eng.	$ 252.79	$ 1,307.96	$ 752.02	$ 1,046.60	$ 759.94	$ 2,884.10		$ 1,614.17	
15110	Maintenance of Structures	222,322.32	220,841.41	189,584.23	220,866.03	157,382.57	137,550.51	132,311.96	287,006.46	
15123	Maintenance of Boilers	1,323,363.70	2,430,267.70	1,797,446.64	1,620,690.17	1,124,329.63	837,053.75	1,287,440.79	1,463,673.12	
15131	Maint. of Turbine & Gen.	381,387.80	523,061.83	275,012.19	487,509.60	280,420.19	158,331.73	1,088,423.58	127,913.04	
15140	Maint. Of Misc. Steam Plant	246,620.02	293,831.92	212,979.05	200,397.92	296,192.02	229,247.02	300,528.80	335,528.55	
	Total	$ 2,173,946.63	$ 3,469,310.82	$ 2,475,774.13	$ 2,530,510.32	$ 1,859,084.35	$ 1,365,067.11	$ 2,808,705.13	$ 2,215,735.34	
	Year-to-year change		$ 1,295,364.19	$ (993,536.69)	$ 54,736.19	$ (671,425.97)	$ (494,017.24)	$ 1,443,638.02	$ (592,969.79)	
	Lewis & Clark	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**YTD 9/30/2015**
15100	Maint. Supervision & Eng.	$ 2,826.06	$ 3,600.40	$ 2,392.79	$ 3,586.12	$ 4,930.21	$ 1,251.91	$ 2,175.54	$ 14,732.45	$ 4,688.67
15110	Maintenance of Structures	32,476.82	33,817.20	162,312.45	81,659.22	303,903.51	169,600.98	53,560.42	115,225.28	$ 118,334.19
15123	Maintenance of Boilers	429,075.03	452,229.84	447,063.38	446,900.89	405,183.37	506,866.56	418,991.82	782,572.98	$ 744,505.44
15131	Maint. of Turbine & Gen.	48,515.08	36,258.92	28,956.83	117,875.92	53,752.01	987,284.09	102,180.14	85,850.66	$ 58,438.03
15140	Maint. Of Misc. Steam Plant	35,028.83	47,699.73	33,517.78	74,849.83	42,631.26	88,545.09	54,035.98	55,361.58	$ 39,770.28
	Total	$ 547,921.82	$ 573,606.09	$ 674,243.23	$ 724,871.98	$ 810,400.36	$ 1,753,548.63	$ 630,943.90	$ 1,053,742.95	$ 965,736.61
	Year-to-year change		$ 25,684.27	$ 100,637.14	$ 50,628.75	$ 85,528.38	$ 943,148.27	$ (1,122,604.73)	$ 422,799.05	$ (88,006.34)

MONTANA-DAKOTA UTILITIES CO.

RESPONSE TO DATA REQUEST: LCG-044

Montana

	Coyote Station - 25% Share	2007	2008	2009	2010	2011	2012	2013	2014
849C.5260.15100	Maint. Supervision & Eng.	$ 37,184.25	$ 38,526.29	$ 39,018.79	$ 44,166.06	$ 39,782.21	$ 43,824.18	$ 35,035.56	$ 43,989.48
849C.5260.15110	Maintenance of Structures	24,762.70	31,786.17	27,339.03	29,437.23	29,516.95	30,325.00	50,094.66	43,515.55
849C.5260.15124	Maintenance of Boilers	276,258.54	357,081.34	423,330.34	302,648.85	368,894.41	445,688.59	317,024.25	333,463.11
849C.5260.15131	Maint. of Turbine & Gen.	47,854.68	41,620.41	156,937.64	57,660.67	45,604.91	137,842.56	61,577.92	41,711.09
849C.5260.15140	Maint. Of Misc. Steam Plant	40,664.55	47,630.00	68,802.52	60,773.36	54,724.26	65,924.73	49,772.56	62,875.85
	Total	$ 426,724.72	$ 516,644.21	$ 715,428.32	$ 494,686.17	$ 538,522.74	$ 723,605.06	$ 513,504.95	$ 525,555.08
	Year-to-year change		$ 89,919.49	$ 198,784.11	$ (220,742.15)	$ 43,836.57	$ 185,082.32	$ (210,100.11)	$ 12,050.13

	Big Stone Station	2007	2008	2009	2010	2011	2012	2013	2014	YTD 9/30/2015
861000.5250.15100	Maint. Supervision & Eng.	$ 29,008.46	$ 29,023.70	$ 30,099.25	$ 30,246.49	$ 32,450.80	$ 34,206.54	$ 34,330.26	$ 30,388.51	$ 23,753.67
861000.5250.15110	Maintenance of Structures	28,091.18	25,596.17	21,380.19	21,373.74	21,891.88	27,818.35	31,986.79	28,806.07	$ 51,335.16
861000.5250.15123	Maintenance of Boilers	255,313.55	203,348.94	196,585.66	202,069.48	339,798.85	228,466.06	231,616.59	235,463.37	$ 312,952.76
861000.5250.15131	Maint. of Turbine & Gen.	30,931.65	66,681.74	4,068.65	32,709.15	73,845.99	39,918.78	52,182.32	63,198.00	$ 275,851.62
861000.5250.15140	Maint. Of Misc. Steam Plant	28,577.65	29,106.33	26,468.87	26,399.23	31,695.55	29,989.01	36,430.16	41,118.75	$ 31,323.70
	Total	$ 371,922.49	$ 353,756.88	$ 278,602.62	$ 312,798.09	$ 499,683.07	$ 360,398.74	$ 386,546.12	$ 398,974.70	$ 695,216.91
	Year-to-year change		$ (18,165.61)	$ (75,154.26)	$ 34,195.47	$ 186,884.98	$ (139,284.33)	$ 26,147.38	$ 12,428.58	$ 296,242.21

	Heskett	2007	2008	2009	2010	2011	2012	2013	2014
15100	Maint. Supervision & Eng.	$ 62.43	$ 327.57	$ 186.70	$ 259.21	$ 182.92	$ 652.09	$ -	$ 362.04
15110	Maintenance of Structures	54,906.23	55,308.66	47,261.71	54,699.27	37,882.64	31,100.27	30,620.52	64,371.91
15123	Maintenance of Boilers	326,827.02	608,648.35	447,093.47	401,376.85	270,630.74	189,258.34	297,948.15	328,283.24
15131	Maint. of Turbine & Gen.	94,190.14	130,998.20	68,270.02	120,735.62	67,498.26	35,798.90	251,890.21	28,689.30
15140	Maint. Of Misc. Steam Plant	60,906.98	73,588.75	52,912.20	49,630.15	71,294.65	51,832.87	69,550.32	75,254.81
	Total	$ 536,892.80	$ 868,871.53	$ 615,724.10	$ 626,701.10	$ 447,489.21	$ 308,642.47	$ 650,009.20	$ 496,961.30
	Year-to-year change		$ 331,978.73	$ (253,147.43)	$ 10,977.00	$ (179,211.89)	$ (138,846.74)	$ 341,366.73	$ (153,047.90)

	Lewis & Clark	2007	2008	2009	2010	2011	2012	2013	2014	YTD 9/30/2015
15100	Maint. Supervision & Eng.	$ 697.92	$ 901.72	$ 595.46	$ 888.12	$ 1,186.75	$ 283.06	$ 503.47	$ 3,304.31	$ 1,061.64
15110	Maintenance of Structures	8,020.68	8,469.37	40,292.84	20,223.55	73,150.84	38,346.86	12,395.34	25,843.70	26,794.18
15123	Maintenance of Boilers	107,330.47	113,445.38	111,353.94	110,678.66	97,529.35	114,602.72	96,965.84	175,521.08	168,576.80
15131	Maint. of Turbine & Gen.	12,408.58	9,281.96	7,187.68	29,192.91	12,938.33	223,225.42	23,647.23	19,255.27	13,232.00
15140	Maint. Of Misc. Steam Plant	8,650.99	11,946.17	8,334.56	18,537.19	10,261.54	20,020.07	12,505.37	12,416.91	9,005.07
	Total	$ 137,108.64	$ 144,044.60	$ 167,764.48	$ 179,520.43	$ 195,066.81	$ 396,478.13	$ 146,017.25	$ 236,341.27	$ 218,669.69
	Year-to-year change		$ 6,935.96	$ 23,719.88	$ 11,755.95	$ 15,546.38	$ 201,411.32	$ (250,460.88)	$ 90,324.02	$ (17,671.58)

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
THIRD DATA REQUEST
DATED OCTOBER 12, 2015
DOCKET NO. D2015.6.51

LCG-045 RE: Major Overhaul of MDU Generation Units

For each applicable generation unit, please provide the major overhaul expense included in the Company's proposed revenue requirement by FERC Account, on a Total Company and Montana jurisdictional basis, in Excel format with formulas intact. Please cite to the locations in the Company's filing where these expenses are detailed quantitatively and integrated into the revenue requirement.

Response:

The major overhaul expenses included in the proposed revenue requirement are intended to reflect the expense associated with a typical major overhaul. The Company's generation fleet experiences approximately one major overhaul outage per year. See Response LCG-044 a.

The major overhaul expenses specifically included in the proposed revenue requirement are detailed on Statement Workpapers, Schedule G, Page G-78, Big Stone Plant. These overhaul expenses are included in the Big Stone pro forma adjustments on Statement G, Page 14, Adjustment No. 13. See the attached Excel file labeled Response No. LCG-045 Attachment A Big Stone.

Any other incidental major overhaul costs included in the proposed revenue requirement would primarily be reflected in Statement G, Page 13, Adjustment No. 12, Subcontract Labor and Statement G, Page 15, Adjustment No. 14, Materials.

BIG STONE PLANT
2015 OPERATING & MAINTENANCE PROJECTIONS - MDU Share 22.7%

Payroll and Other Expenses:		Major Outage Costs		MT Share 1/	
510	Maintenance Supervision & Engineering				
511	Maintenance of Structures	$	90,800	$	20,560
512	Maintenance of Boiler Plant		797,822		180,649
513	Maintenance of Electric Plant		973,490		220,425
514	Maintenance of Misc. Steam Plant		85,579		19,377
556	Dispatching (Other Power Supply)				
Total Payroll and Other Expenses		$	1,947,691	$	441,011

1/ Allocated on Factor # 15: Integrated System 12 month Peak Demand.
22.64279%

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
FOURTH DATA REQUEST
DATED OCTOBER 13, 2015
DOCKET NO. D2015.6.51

LCG-046 Re: Direct Testimony of Travis R. Jacobson, page 10, line 21 through page 11, line 6 and the Direct Testimony of Darcy J. Neigum, page 33, line 5 through page 39, line 7.

a. What is the date at which the joint use agreement between MDU and BEPC expires?

b. How does the expiration date of the MDU/BEPC contract relate to the October 1, 2015 date at which BEPC and WAPA intend to join SPP as referenced on p. 33, line 13 of Mr. Neigum's direct testimony?

c. Please identify the amount of the reduction in transmission (and distribution) charges reflected in Adjustment No. 11 that are expected to be incurred only during Calendar Year 2015 (i.e., without annualization) using the same format as Statement G, p. 12.

d. Please identify the amount of the increase in transmission charges reflected in Adjustment No. 12 that are expected to be incurred only during Calendar Year 2015 (i.e., without annualization) using the same format as Statement G, p. 13 (but limited to the transmission entry).

e. Does the pro-forma entry for transmission in Statement G, p. 13 reflect any increased costs expected by MDU due to the upcoming expiration of the TSA with WAPA on December 31, 2015 discussed on p. 33 of Mr. Neigum's direct testimony? If yes, please explain how this was accounted for and identify any workpapers supporting the calculation of such costs.

f. Does the pro-forma entry for transmission in Statement G, p. 13 reflect any increased costs expected by MDU associated with 2016 RECB I project costs discussed on p. 39 of Mr. Neigum's direct testimony? If yes, please explain how this was accounted for and identify any workpapers supporting the calculation of such costs.

g. Please refer to Workpaper G-63.
   i. On what date was the $0.80/MWh 2015 MVP Charge effective?

   ii. Is the $101,908 Pro Forma Adjustment for MVP calculated on a Calendar Year 2015 basis or an annualized 2015 basis?

Response:

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
FOURTH DATA REQUEST
DATED OCTOBER 13, 2015
DOCKET NO. D2015.6.51

a. The Interconnection and Common Use Agreement (ICCUA) between MDU and BEPC will end at midnight on December 31, 2015.

b. Beginning October 1, 2015, MDU will need to take incremental network transmission service from SPP to replace the incremental network transmission under the WAPA IS Tariff which ended at midnight on September 30, 2015.

   Both the WAPA Transmission Service Agreement (TSA) and Basin ICCUA expire at midnight December 31, 2015. MDU will need to take SPP network transmission service to replace service previously provided under the WAPA TSA and Basin ICCUA.

c. As noted in Response LCG-046, part a. above, the Facility Charge, Statement G, Page 12, Adjustment No. 11 will cease on December 31, 2015. The year-to-date 2015 transmission and facility charges incurred are reflected below, as well as an estimate for the remainder of the year.

TRANSMISSION CHARGES
ELECTRIC UTILITY - MONTANA

	YTD 9/30/15	4th Qtr.	Total 2015
WAPA NITS	$269,236	$0	$269,236
SPP Network Transmission Svc.	0	89,745	89,745
Transmission - Other	272,163	90,721	362,884
MISO Schedule 26-RECB	643,760	214,587	858,347
Subtotal Transmission Adjust No. 12	1,185,159	395,053	1,580,212
Facility Charge Adjust No. 11	135,011	45,004	180,015
	$1,320,170	$440,057	$1,760,227

d. As noted in Response LCG-046, part b. above, WAPA NITS will cease on September 30, 2015. The Company will need to take a similar SPP network transmission service to replace service previously provided by WAPA. The SPP transmission service will be charged at SPP's tariff rate. An estimate is shown in Response LCG-046, part c.

e. Yes, increased costs expected by MDU due to the upcoming expiration of the TSA with WAPA on December 31, 2015 were included in the increase reflected in transmission charges on Statement G, page 13 of $1,330,652.

**MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
FOURTH DATA REQUEST
DATED OCTOBER 13, 2015
DOCKET NO. D2015.6.51**

Statement Workpapers, Statement G, page G-62, Transmission Charge Workpaper pro forma adjustment of $1,620,619 is calculated as follows:

TRANSMISSION CHARGE WORKPAPER

	Pro Forma				
	Total Company		Montana		Pro Forma Adjustment
Increased Transmission Service Charge	$4,000,000	1/	$905,712	2/	$905,712
Facility Charge Replacement Charge	1,967,208		445,431	2/	445,431
WAPA NITS Replacement Charge	269,476		269,476	3/	269,476
	$6,236,684		$1,620,619		$1,620,619

1/ Per Mr. Neigum's direct testimony, page 36.
2/ Allocated on Factor 15: Integrated System Peak Demand
3/ Direct assignment of costs to Montana.

f. MISO charges noted in Mr. Neigum's testimony have been adjusted to reflect the 2015 rate and 2014 system requirements. See Response LCG-046, part g. below.

g.
  i. The $0.80/Mwh 2015 MVP Charge was effective 1/1/2015.
  ii. The $101,908 pro forma adjustment for MVP is calculated on a 2015 calendar year basis using 2014 calendar year system requirements.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
FOURTH DATA REQUEST
DATED OCTOBER 13, 2015
DOCKET NO. D2015.6.51

LCG-047 Re: Direct Testimony of Travis R. Jacobson, page 24, line 5 through page 25, line 13 and Exhibit TRJ-3.

a. Please explain why Footnote 1 in Exhibit TRJ-3 does not indicate the assessment rate that was applicable starting October 2012. Please identify the applicable assessment rate(s) from October 2012 through March 2015.

b. Please explain why MDU calculated its claimed under-recovery of PSC and MCC taxes in Exhibit TRJ-3 by first converting its deemed recovery (in columns 7-8) using a cents/kWh rate (per Footnote 3) rather than by simply applying the approved 0.24% total tax rate directly to the revenues in the second column of Exhibit TRJ-3. Why doesn't this latter approach produce a more accurate depiction of actual tax recovery?

Response:

a. The rates were inadvertently omitted. The effective rates for the PSC and MCC, respectively, are as follows:
   - October 1, 2012 – 0.23% and 0.07%
   - October 1, 2013 – 0.42% and 0.11%
   - October 1, 2014 – 0.2% and 0.1%
   - October 1, 2015 – 0.23% and 0.06%

b. The amount of total revenue fluctuates over time as fuel and purchased power costs change while the amount of revenue approved in the most recent rate case is a static amount based on the rate in effect at that time. Therefore, in order to determine the amount of revenue collected from the customer relative to the PSC and MCC taxes, the conversion to a cents/kWh must be computed.

MONTANA-DAKOTA UTILITIES CO.
MONTANA LARGE CUSTOMER GROUP
SEVENTH DATA REQUEST
DATED OCTOBER 21, 2015
DOCKET NO. D2015.6.51

LCG-072 RE: Base Fuel and Purchased Power Charge

Please provide all workpapers in Excel format with formulas intact that derive the proposed Base Fuel and Purchased Power Charge for each rate schedule, demonstrating how the proposed charge for each schedule relates to the average Pro Forma Base Cost of Fuel of $0.02517 per kWh from Statement G, page 5, using service voltage loss factors.

Response:

Please see Response No. LCG-072 Attachment A on the enclosed CD.

MONTANA-DAKOTA UTILITIES CO.
FUEL AND PURCHASED POWER - MONTANA
PRO FORMA 2015

	Total 1/	Allocation 2/ to Montana	Allocation to 3/ Primary	Secondary	Contract
Fuel & Purchased Power Costs					
Account 501, 502 and 547	$53,099,800	$14,091,451	$1,076,962	$9,057,942	$3,956,547
Account 555 Energy	18,791,970	4,986,952	381,136	3,205,598	1,400,218
Account 555 Energy - Fort Peck	475,630	475,630	50,542	425,088	0
Account 555 Demand and 547 Pipeline Charges	3,153,180	713,968	67,101	484,679	162,188
Total Fuel & Purchased Power	$75,520,580	$20,268,001	$1,575,741	$13,173,307	$5,518,953
Fuel Costs - Sales for Resale	0	0	0	0	0
Net System Costs	$75,520,580	$20,268,001	$1,575,741	$13,173,307	$5,518,953
Kwh Retail Sales	3,031,848,602	805,309,558	61,773,911	514,981,222	228,554,425
Cost Per Kwh	$0.02491	$0.02517	$0.02551	$0.02558	$0.02415

1/ Page _.
2/ Energy and Reagent are allocated on Allocation Factor No. 16: Integrated System Kwh Sales and Demand is allocated on Allocation Factor No. 15: Integrated System Peak Demand, except Fort Peck which is 100% Montana.
3/ Energy and Reagent are allocated on Kwh sales at supply and Demand is allocated on Class Allocation Factor No. 2: Coincident KW @ Supply. Fort Peck is allocated to Primary and Secondary only.

	Montana	Primary	Secondary	Contract
Demand - Class Factor No. 2		9.398338%	67.885240%	22.716422%
Demand - Juris Factor No. 15	22.642790%			
Energy - Juris Factor No. 16	26.537673%			
Energy - Fort Peck	100.000000%	10.626266%	89.373734%	
Energy Calculation				
Sales @ meter - Pro Forma	805,309,558	61,773,911	514,981,222	228,554,425
Loss Factor		6.92000%	7.74000%	6.26000%
Adjust to generation	868,368,584	66,366,471	558,184,719	243,817,394
% at generation	100.000000%	7.642661%	64.279700%	28.077639%
1-loss factor		0.9308	0.9226	0.9374

MONTANA-DAKOTA UTILITIES CO.
FUEL AND PURCHASED POWER
ELECTRIC UTILITY - MONTANA
TWELVE MONTHS ENDING DECEMBER 31, 2014
PRO FORMA 2015

	Per Books 1/		Pro Forma	
	Total	Montana	Total 2/	Montana
Fuel Expense				
Acct. 501	$47,318,443	$12,268,043	$49,558,420	$13,151,651
Acct. 502 - Reagent	0	0	1,984,630	526,675
Acct. 547	1,673,424	456,358	1,556,750	413,125
	48,991,867	12,724,401	53,099,800	14,091,451
Purchased Power / Pipeline Charges				
Energy	27,853,938	6,966,638	18,791,970	4,986,952
Energy - Ft. Peck	475,515	475,515	475,630	475,630
Demand	8,470,002	955,056	632,430	143,200
Heskett III Pipeline Charges	1,144,236	256,637	2,520,750	570,768
Total Purchased Power/Pipeline Charges	37,943,691	8,653,846	22,420,780	6,176,550
Other				
Deferred F&PP	1,518,982	699,697		
Allowances - Acct. 509	53	0		
Total	88,454,593	22,077,944	75,520,580	20,268,001
Fuel & Purchased Power - Sales for Resale	502,697	137,090	0	0
Net Fuel & Purchased Power	$87,951,896	$21,940,854	$75,520,580	$20,268,001
Kwh Sales		804,582,058		805,309,558
Cost per Kwh		$0.02727		$0.02517

1/ Excludes non-fuel expenses that are recorded in the Fuel & Purchased Power account.
2/ Pro Forma total reflects integrated system only. Wyoming fuel & purchased power costs are excluded.

Other non-fuel costs included in 501	Total	Montana
Labor	$587,090	$160,105
Subcontract Labor	130,566	35,607
Fuel Handling @ Big Stone & Coyote	104,296	28,442
Materials	30,728	8,380
Vehicles	4,297	1,172
Total	856,977	233,706
Total Fuel & Purchased Power	89,311,570	22,311,650
Jurisdictionals	89,311,570	22,311,650
Difference	0	0

Factors:	2014	2015
#15 - Demand	22.428695%	22.642790%
#16 - Energy	27.270911%	26.537673%

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED SEPTEMBER 23, 2015
DOCKET NO. D2015.6.51

PSC-022
Regarding: Load Forecast
Witness: Neigum

a. **Provide any updates to the 2015 IRP load forecast that MDU develops during the course of the proceeding in this Docket. (See 2015 Integrated Resource Plan Vol. 1, p. 23.)**

b. **How would MDU's near term action plan be affected by a significant drop in expected load due to slowed growth in the Bakken area?**

c. **Provide any Bakken-specific load forecasts MDU has developed**

Response:

a. Please see Attachment A for the preliminary forecasted schedules.

Preliminary results of the 2015-2035 long-range energy and demand forecast for the Integrated System of Montana, North Dakota, and South Dakota are included in Attachment A. Historical and forecasted sales by state are plotted on page 2 of Attachment A while sales by class and in total for the Integrated System are plotted on page 3 of Attachment A. The forecast results provided in Attachment A reflect the demand-side management (DSM) programs that are being implemented as a result of the 2015 IRP.

The sales forecasts were developed by state again this year; the forecast for 2012-2032 was the first to do so. With this change, the expected growth in North Dakota and Montana due to the Bakken Oil Field activity can be reflected more accurately. Seasonal peak demand continues to be developed on an Integrated System basis with allocations to the states.

Total sales in the new forecast are projected to grow at a five-year average rate of 3.06% per year for 2015-2020 compared to a growth rate of 4.65% per year for the same time period in last year's forecast. In addition to the lower growth rate, total sales volumes to start are also lower than last year: total sales for 2016 in the new forecast are 3,280.8 GWh while in last year's forecast, total sales for 2016 were projected to be 3,506.2 GWh, a decrease of 225.4 GWh or 6.4%. The majority of this decrease occurs in the Large C&I sales sector.

**MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
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In the new forecast, the sales growth rate for the residential sales sector is projected to be 2.5% for the next five years compared to a five-year growth rate of 2.8% per year for the same time period in last year's forecast. The forecast starting point in 2016 for the residential sales sector is approximately 0.5% lower than last year and volumes projected in the new forecast compared to last year's forecast are just slightly lower throughout the forecast horizon. One of the primary drivers for the residential sales forecast is growth in customers; residential customer growth is again projected to be fairly strong which is what we are currently seeing. Attachment A page 4 summarizes the residential sales and customer forecasts for both this year's and last year's forecasts.

For the Small C&I sales sector, the growth rate is projected to be 5.5% per year for the next five years in the new forecast, compared to 6.5% per year for the same five years from last year's forecast. The new forecast starting point for the Small C&I sales sector is approximately 6.0% lower than last year and the volumes remain lower throughout the forecast horizon. The primary driver for the Small C&I sector is employment and the employment forecast for both North Dakota and Montana is tied to the higher growth in residential customers.

For the LC&I sector in total, the 2016 sales as projected in the new forecast are 12.7% lower than what was forecasted last year.

A summary of the forecasted energy and peak demand by season is given on Attachment A, page 5. A primary driver for the summer and winter peak demand forecasts is projected annual energy requirements. With energy requirements forecasted to increase at 1.9% over the forecast horizon, summer and winter peak demand are projected to grow at 1.4% and 1.9% respectively.

b. Montana-Dakota does not see a change in its near term action plan identified in the 2015 IRP based upon the '2015-2035 Preliminary Load Forecast'.

c. Please see Attachment B. Attachment B is a transmission expansion planning forecast for the Bakken region that Montana-Dakota last updated December 19, 2013. The forecast was used to study Montana-Dakota's electric transmission system in the Bakken Area to determine potentially impacted transmission facilities based upon forecasted customer growth.

Exhibit 1
Montana-Dakota Utilities Co.
Historical and Forecasted Annual Sales by Sector
Integrated System
Billing Month Basis
Reflecting Demand-Side Programs

YEAR	Residential Sales (MWh)	% Change	Small C&I Sales (MWh)	% Change	Large C&I Sales (MWh)	% Change	Street Lighting Sales (MWh)	% Change	Miscellaneous Sales (MWh)	% Change	Total Sales Sales (MWh)	% Change	Total Energy Requirements MWh	% Change
2004	680,613		355,984		907,267		30,555		48,061		2,022,480		2,204,012	
2005	737,106	8.30%	386,747	8.64%	957,168	5.50%	30,376	-0.59%	49,328	2.64%	2,160,725	6.84%	2,327,117	5.59%
2006	768,953	4.32%	413,148	6.83%	962,185	0.52%	30,601	0.74%	53,471	8.40%	2,228,358	3.13%	2,397,793	3.04%
2007	793,914	3.25%	443,914	7.45%	984,671	2.34%	30,773	0.56%	53,953	0.90%	2,307,225	3.54%	2,510,540	4.70%
2008	814,895	2.64%	465,654	4.90%	1,023,079	3.90%	31,081	1.00%	53,706	-0.46%	2,388,415	3.52%	2,596,990	3.44%
2009	846,289	3.85%	490,271	5.29%	991,617	-3.08%	30,433	-2.08%	53,682	-0.04%	2,412,292	1.00%	2,593,368	-0.14%
2010	874,597	3.34%	529,486	8.00%	980,626	-1.11%	30,215	-0.72%	52,262	-2.65%	2,467,186	2.28%	2,718,192	4.81%
2011	946,595	8.23%	606,453	14.54%	977,070	-0.36%	29,776	-1.45%	55,783	6.74%	2,615,677	6.02%	2,776,082	2.13%
2012	957,183	1.12%	679,919	12.11%	948,828	-2.89%	29,802	0.09%	58,464	4.81%	2,674,196	2.24%	2,919,752	5.18%
2013	1,044,088	9.08%	724,960	6.62%	992,069	4.56%	29,584	-0.73%	57,014	-2.48%	2,847,715	6.49%	3,115,064	6.69%
2014	1,088,204	4.23%	784,888	8.27%	1,068,540	7.71%	29,774	0.64%	60,443	6.01%	3,031,849	6.47%	3,250,683	4.35%
2015	1,127,022	3.57%	813,679	3.67%	1,111,709	4.04%	29,774	0.00%	60,935	0.81%	3,143,119	3.67%	3,402,238	4.66%
2016	1,165,895	3.45%	870,899	7.03%	1,152,764	3.69%	29,774	0.00%	61,427	0.81%	3,280,759	4.38%	3,551,225	4.38%
2017	1,195,639	2.55%	920,299	5.67%	1,178,473	2.23%	29,774	0.00%	61,919	0.80%	3,386,104	3.21%	3,665,254	3.21%
2018	1,225,522	2.50%	971,075	5.52%	1,195,226	1.42%	29,774	0.00%	62,410	0.79%	3,484,007	2.89%	3,771,229	2.89%
2019	1,255,541	2.45%	1,024,477	5.50%	1,211,954	1.40%	29,774	0.00%	62,902	0.79%	3,584,648	2.89%	3,880,166	2.89%
2020	1,274,540	1.51%	1,063,688	3.83%	1,228,686	1.38%	29,774	0.00%	63,395	0.78%	3,660,083	2.10%	3,961,820	2.10%
2021	1,293,607	1.50%	1,104,952	3.88%	1,246,502	1.45%	29,774	0.00%	63,887	0.78%	3,738,722	2.15%	4,046,942	2.15%
2022	1,310,124	1.28%	1,146,103	3.72%	1,261,376	1.19%	29,774	0.00%	64,379	0.77%	3,811,756	1.95%	4,125,997	1.95%
2023	1,322,154	0.92%	1,183,048	3.22%	1,278,090	1.33%	29,774	0.00%	64,871	0.76%	3,877,937	1.74%	4,197,634	1.74%
2024	1,333,673	0.87%	1,219,176	3.05%	1,294,195	1.26%	29,774	0.00%	65,362	0.76%	3,942,180	1.66%	4,267,173	1.66%
2025	1,344,072	0.78%	1,255,488	2.98%	1,311,291	1.32%	29,774	0.00%	65,854	0.75%	4,006,479	1.63%	4,336,773	1.63%
2026	1,353,961	0.74%	1,291,982	2.91%	1,328,658	1.32%	29,774	0.00%	66,346	0.75%	4,070,721	1.60%	4,406,311	1.60%
2027	1,363,849	0.73%	1,329,248	2.88%	1,346,299	1.33%	29,774	0.00%	66,839	0.74%	4,136,009	1.60%	4,476,982	1.60%
2028	1,372,705	0.65%	1,366,084	2.77%	1,364,215	1.33%	29,774	0.00%	67,331	0.74%	4,200,109	1.55%	4,546,366	1.55%
2029	1,381,560	0.65%	1,403,653	2.75%	1,382,416	1.33%	29,774	0.00%	67,823	0.73%	4,265,226	1.55%	4,616,851	1.55%
2030	1,390,415	0.64%	1,441,972	2.73%	1,400,906	1.34%	29,774	0.00%	68,314	0.72%	4,331,381	1.55%	4,688,460	1.55%
2031	1,399,270	0.64%	1,481,041	2.71%	1,419,691	1.34%	29,774	0.00%	68,806	0.72%	4,398,582	1.55%	4,761,201	1.55%
2032	1,408,114	0.63%	1,520,875	2.69%	1,438,773	1.34%	29,774	0.00%	69,298	0.72%	4,466,834	1.55%	4,835,080	1.55%
2033	1,416,458	0.59%	1,560,830	2.63%	1,458,162	1.35%	29,774	0.00%	69,790	0.71%	4,535,014	1.53%	4,908,881	1.53%
2034	1,424,790	0.59%	1,601,557	2.61%	1,477,860	1.35%	29,774	0.00%	70,282	0.70%	4,604,263	1.53%	4,983,838	1.53%
2035	1,433,134	0.59%	1,643,320	2.61%	1,497,952	1.36%	29,774	0.00%	70,774	0.70%	4,674,954	1.54%	5,060,357	1.54%
2004-2014 Average Yearly Growth (10 Years History)		4.48%		8.24%		0.79%		-0.37%		1.87%		3.66%		3.65%
2009-2014 Average Yearly Growth (5 Years History)		5.28%		10.23%		1.09%		-0.49%		2.61%		4.66%		4.64%
2015-2020 Average Yearly Growth (5 Years)		2.49%		5.52%		1.92%		0.00%		0.79%		3.06%		3.06%
2015-2025 Average Yearly Growth (10 Years)		1.73%		4.34%		1.53%		0.00%		0.78%		2.37%		2.37%
2015-2035 Average Yearly Growth (20 Years)		1.06%		3.35%		1.39%		0.00%		0.75%		1.85%		1.85%

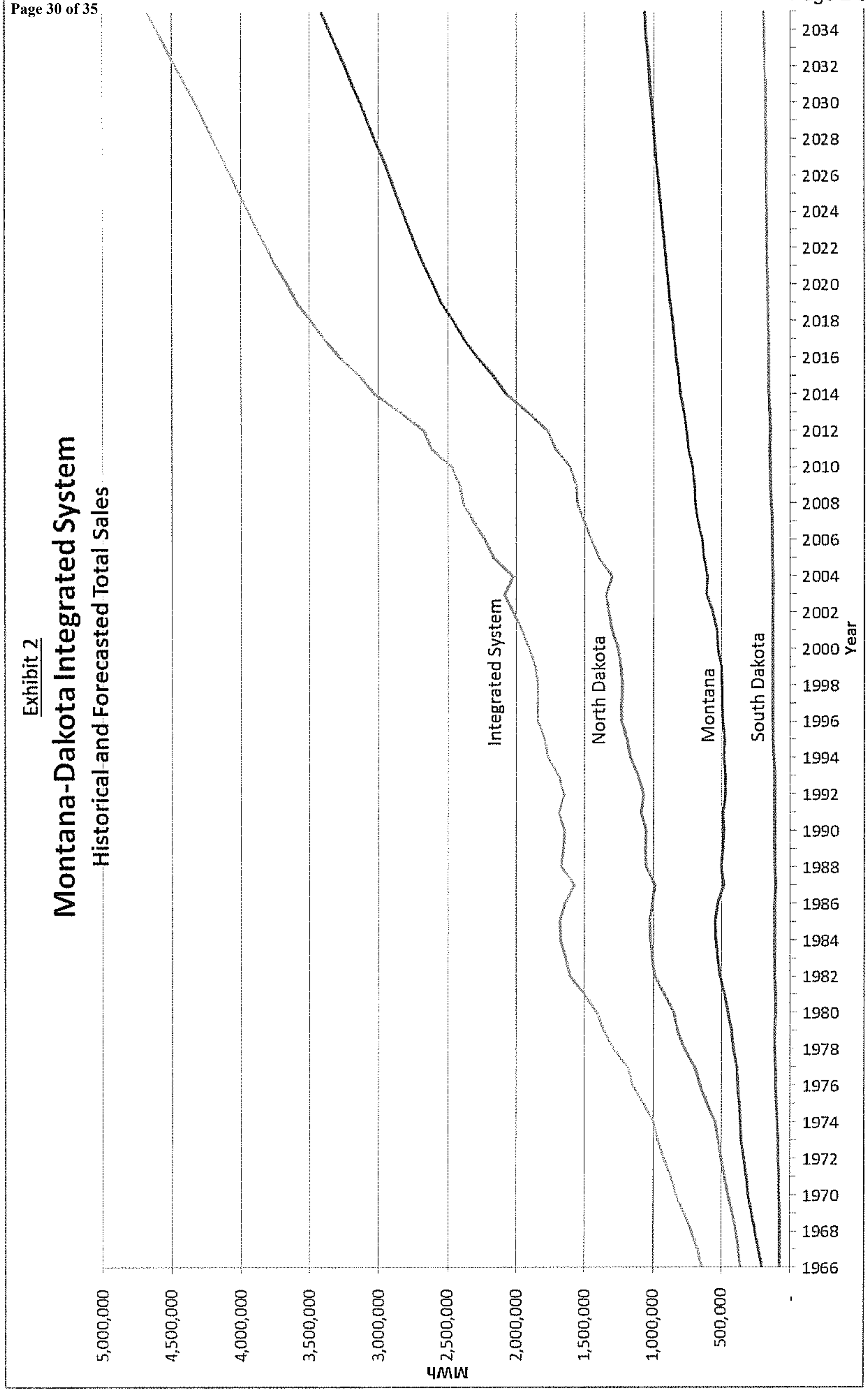
Exhibit 2
Montana-Dakota Integrated System
Historical and Forecasted Total Sales
Integrated System
North Dakota
Montana
South Dakota
MWh
Year
5,000,000
4,500,000
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
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2028
2030
2032
2034

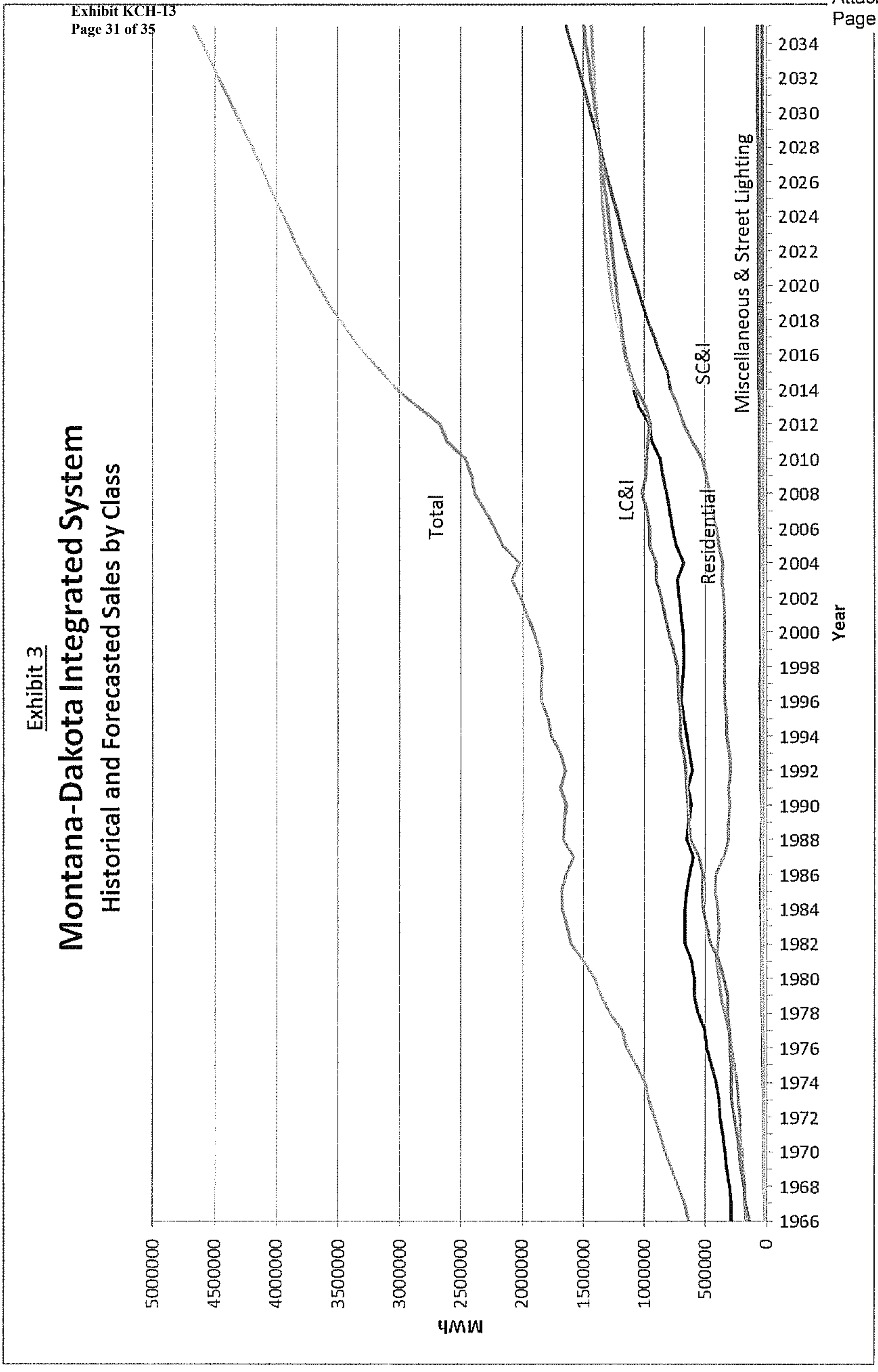
Exhibit 3
Montana-Dakota Integrated System
Historical and Forecasted Sales by Class
Total
LC&I
Residential
SC&I
Miscellaneous & Street Lighting
MWh
Year
5000000
4500000
4000000
3500000
3000000
2500000
2000000
1500000
1000000
500000
0
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034

Exhibit 4
Montana-Dakota Utilities Co.
Comparison of 2014 and 2015 Residential Forecasts
Integrated System

2014 Forecast

Year	Sales (MWh)	% Change	Avg Custs	Cust No Inc/(Dec)	Avg Use Per Cust (kWh/Yr)	% Change
2004	680,614		85,498		7,961	
2005	737,106	8.30%	85,791	293	8,592	7.93%
2006	768,952	4.32%	86,150	359	8,926	3.89%
2007	793,914	3.25%	86,575	425	9,170	2.74%
2008	814,895	2.64%	87,262	687	9,338	1.83%
2009	846,289	3.85%	87,887	625	9,629	3.11%
2010	874,598	3.35%	88,944	1,057	9,833	2.12%
2011	946,595	8.23%	90,681	1,737	10,439	6.16%
2012	957,183	1.12%	93,695	3,014	10,216	-2.13%
2013	1,044,088	9.08%	97,155	3,460	10,747	5.19%
2014	1,088,204	4.23%	100,406	3,251	10,838	0.85%
2015	1,129,171	3.76%	103,913	3,507	10,867	0.26%
2016	1,171,249	3.73%	107,266	3,353	10,919	0.48%
2017	1,204,234	2.82%	109,766	2,500	10,971	0.47%
2018	1,237,598	2.77%	112,266	2,500	11,024	0.48%
2019	1,271,227	2.72%	114,765	2,499	11,077	0.48%
2020	1,293,812	1.78%	116,263	1,498	11,128	0.47%
2021	1,316,639	1.76%	117,760	1,497	11,181	0.47%
2022	1,333,347	1.27%	119,257	1,497	11,180	0.00%
2023	1,345,485	0.91%	120,352	1,095	11,180	-0.01%
2024	1,357,106	0.86%	121,397	1,045	11,179	0.00%
2025	1,367,591	0.77%	122,342	945	11,178	-0.01%
2026	1,377,547	0.73%	123,236	894	11,178	0.00%
2027	1,387,491	0.72%	124,129	893	11,178	0.00%
2028	1,396,412	0.64%	124,923	794	11,178	0.00%
2029	1,405,311	0.64%	125,715	792	11,179	0.00%
2030	1,414,222	0.63%	126,508	793	11,179	0.00%
2031	1,423,121	0.63%	127,300	792	11,179	0.00%
2032	1,432,020	0.63%	128,092	792	11,180	0.00%
2033	1,440,402	0.59%	128,834	742	11,180	0.01%
2034	1,448,784	0.58%	129,576	742	11,181	0.01%

	Sales	Custs	Use/Cust
2004-2014 Average Yearly Growth (10 Years History)	4.48%	1.53%	2.91%
2009-2014 Average Yearly Growth (5 Years History)	5.28%	2.79%	2.42%
2015-2020 Average Yearly Growth (5 Years)	2.76%	2.27%	0.48%
2015-2025 Average Yearly Growth (10 Years)	1.89%	1.59%	0.30%
2015-2034 Average Yearly Growth (19 Years)	1.15%	1.04%	0.12%

2015 Forecast

Year	Sales (MWh)	% Change	Avg Custs	Cust No Inc/(Dec)	Avg Use Per Cust (kWh/Yr)	% Change
2004	680,614		85,498		7,961	
2005	737,106	8.30%	85,791	293	8,592	7.93%
2006	768,952	4.32%	86,150	359	8,926	3.89%
2007	793,914	3.25%	86,575	425	9,170	2.74%
2008	814,895	2.64%	87,262	687	9,338	1.83%
2009	846,289	3.85%	87,887	625	9,629	3.11%
2010	874,598	3.35%	88,944	1,057	9,833	2.12%
2011	946,595	8.23%	90,681	1,737	10,439	6.16%
2012	957,183	1.12%	93,695	3,014	10,216	-2.13%
2013	1,044,088	9.08%	97,155	3,460	10,747	5.19%
2014	1,088,204	4.23%	100,406	3,251	10,838	0.85%
2015	1,127,022	3.57%	103,711	3,305	10,867	0.27%
2016	1,165,895	3.45%	107,014	3,303	10,895	0.26%
2017	1,195,639	2.55%	109,517	2,503	10,917	0.21%
2018	1,225,522	2.50%	112,020	2,503	10,940	0.21%
2019	1,255,541	2.45%	114,523	2,503	10,963	0.21%
2020	1,274,540	1.51%	116,026	1,503	10,985	0.20%
2021	1,293,607	1.50%	117,528	1,502	11,007	0.20%
2022	1,310,124	1.28%	119,030	1,502	11,007	0.00%
2023	1,322,154	0.92%	120,131	1,101	11,006	-0.01%
2024	1,333,673	0.87%	121,182	1,051	11,006	0.00%
2025	1,344,072	0.78%	122,133	951	11,005	-0.01%
2026	1,353,961	0.74%	123,034	901	11,005	0.00%
2027	1,363,849	0.73%	123,935	901	11,005	0.00%
2028	1,372,705	0.65%	124,735	800	11,005	0.00%
2029	1,381,560	0.65%	125,535	800	11,005	0.00%
2030	1,390,415	0.64%	126,335	800	11,006	0.00%
2031	1,399,270	0.64%	127,135	800	11,006	0.00%
2032	1,408,114	0.63%	127,934	799	11,007	0.00%
2033	1,416,458	0.59%	128,684	750	11,007	0.01%
2034	1,424,790	0.59%	129,433	749	11,008	0.01%
2035	1,433,134	0.59%	130,183	750	11,009	0.01%

	Sales	Custs	Use/Cust
2004-2014 Average Yearly Growth (10 Years History)	4.48%	1.53%	2.91%
2009-2014 Average Yearly Growth (5 Years History)	5.28%	2.79%	2.42%
2015-2020 Average Yearly Growth (5 Years)	2.49%	2.27%	0.21%
2015-2025 Average Yearly Growth (10 Years)	1.73%	1.59%	0.13%
2015-2035 Average Yearly Growth (20 Years)	1.06%	1.01%	0.05%

Exhibit 6
Montana-Dakota Utilities Co.
Historical and Forecasted Energy and Demand
Integrated System
Reflecting Demand-Side Management Programs from 2015 IRP
Calendar Month Basis

	Total Energy Requirements (net of DSM and EE)		Summer Peak - MW				Winter Peak 2/				Demand Response		
Year	MWh	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Total Demand Before any DSM or EE	Energy Efficiency (EE)	Demand Net of EE 1/	% Change	Rate 38/39 Interrupt Loads	Commercial Demand Response	Residential Demand Response
2004	2,204,012				458.4				383.9				
2005	2,327,117	5.59%			459.1	0.15%			387.2	0.86%			
2006	2,397,793	3.04%			485.5	5.75%			397.2	2.58%			
2007	2,510,540	4.70%			525.6	8.26%			407.3	2.54%			
2008	2,596,990	3.44%			476.6	-9.32%			455.0	11.71%			
2009	2,593,368	-0.14%			473.8	-0.59%			459.6	1.01%			
2010	2,718,192	4.81%			502.5	6.06%			457.8	-0.39%			
2011	2,776,082	2.13%			535.8	6.63%			510.8	11.58%			
2012	2,919,752	5.18%			573.6	7.05%			516.2	1.06%			
2013	3,115,064	6.69%			546.9	-4.65%			582.1	12.77%			
2014	3,250,683	4.35%			533.0	-2.54%			557.2	-4.28%			
2015	3,409,308	4.88%	626.7	1.5	625.2	17.30%	596.1	1.5	594.6	6.71%	14.4	10.0	-
2016	3,556,705	4.32%	644.2	1.5	642.7	2.80%	622.5	1.5	621.0	4.44%	15.4	12.5	-
2017	3,670,404	3.20%	658.2	1.5	656.7	2.18%	642.8	1.5	641.3	3.27%	16.0	15.0	2.0
2018	3,776,529	2.89%	671.5	1.5	670.0	2.03%	661.8	1.5	660.3	2.96%	16.0	15.0	4.0
2019	3,884,066	2.85%	685.0	1.5	683.5	2.01%	681.1	1.5	679.6	2.92%	16.0	15.0	6.0
2020	3,965,874	2.11%	695.9	1.5	694.4	1.59%	695.7	1.5	694.2	2.15%	16.0	15.0	8.0
2021	4,050,712	2.14%	707.1	1.5	705.6	1.61%	710.9	1.5	709.4	2.19%	16.0	15.0	10.0
2022	4,129,364	1.94%	717.6	1.5	716.1	1.49%	725.0	1.5	723.5	1.99%	16.0	15.0	10.0
2023	4,200,889	1.73%	727.5	1.5	726.0	1.38%	737.8	1.5	736.3	1.77%	16.0	15.0	10.0
2024	4,270,416	1.66%	737.2	1.5	735.7	1.34%	750.2	1.5	748.7	1.68%	16.0	15.0	10.0
2025	4,340,011	1.63%	746.9	1.5	745.4	1.32%	762.7	1.5	761.2	1.67%	16.0	15.0	10.0
2026	4,409,593	1.60%	756.5	1.5	755.0	1.29%	775.1	1.5	773.6	1.63%	16.0	15.0	10.0
2027	4,480,198	1.60%	766.3	1.5	764.8	1.30%	787.7	1.5	786.2	1.63%	16.0	15.0	10.0
2028	4,549,631	1.55%	776.0	1.5	774.5	1.27%	800.2	1.5	798.7	1.59%	16.0	15.0	10.0
2029	4,620,168	1.55%	785.7	1.5	784.2	1.25%	812.8	1.5	811.3	1.58%	16.0	15.0	10.0
2030	4,691,832	1.55%	795.6	1.5	794.1	1.26%	825.6	1.5	824.1	1.58%	16.0	15.0	10.0
2031	4,764,625	1.55%	805.6	1.5	804.1	1.26%	838.6	1.5	837.1	1.58%	16.0	15.0	10.0
2032	4,838,491	1.55%	815.7	1.5	814.2	1.26%	851.9	1.5	850.4	1.59%	16.0	15.0	10.0
2033	4,912,344	1.53%	825.8	1.5	824.3	1.24%	865.1	1.5	863.6	1.55%	16.0	15.0	10.0
2034	4,987,377	1.53%	836.0	1.5	834.5	1.24%	878.5	1.5	877.0	1.55%	16.0	15.0	10.0
2035	5,063,929	1.53%	846.4	1.5	844.9	1.25%	892.2	1.5	890.7	1.56%	16.0	15.0	10.0

1/ Historical demand reported is system actual demand.
2/ Winter Peak is for Nov-Dec of current year and Jan-Apr of following year.

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED OCTOBER 21, 2015
DOCKET NO. D2015.6.51

PSC-071
Witness: Jacobson
Regarding: Financial Impacts of Lewis and Clark Station MATS Compliance and RICE Units, Big Stone Regional Haze Rules Compliance, Hesket III 88 MW Gas Turbine, and Thunder Spirit Wind 107.5 MW

a. **Using the format shown on Attached Worksheet 1, please provide the 2014 historical financial information and the 2015 pro forma financial information for the Hesket II 88 MW Simple Gas Turbine.**
b. **Using the format shown on Attached Worksheet 1, please provide the 2015 pro forma financial information for the Lewis and Clark Station MATS compliance and Rice Units.**
c. **Using the format shown on Attached Worksheet 1, please provide the 2015 pro forma financial information for the Big Stone Regional Haze Rules compliance.**
d. **Using the format shown on Attached Worksheet 1, please provide the 2015 pro forma financial information for the Thunder Spirit Wind Project.**

Please note the worksheet requires the financial impact of these projects on the revenue, expense and rate base accounts as shown. The last column on the worksheet is the "Restated 2014 Test Year." This column is calculated by taking the 2014 Adjusted Test Year as filed and subtracting the previous six columns such that the result is a representation of the 2014 Adjusted Test Year excluding the impact of the Hesket, Lewis and Clark Station, Big Stone, and Thunder Wind Projects.

Response:

Producing the financial effects of removing the identified projects would involve a much more exhaustive analysis than possible within the context of the worksheet provided in this request. For example, removing the Big Stone AQCS project would result in the need to replace a significant baseload resource necessary to serve customers. Replacement capacity and energy would be required if the other projects were removed as well.

The Company has provided the financial information and revenue requirement for each project requested as shown on Response PSC-071, Attachment A.

MONTANA-DAKOTA UTILITIES CO.
REVENUE REQUIREMENTS OF MAJOR ELECTRIC PROJECTS

	Hesket III 88 MW Gas Turbine 2014 Actual Booked	Hesket III 88 MW Gas Turbine 2015 Pro Forma Adjustment	Big Stone 2015 Pro Forma Haze Rules	Lewis and Clark Station 2015 Pro Forma MATS Compliance	Lewis and Clark Station 2015 Pro Forma 18.6 MW RICE Units	Thunderspirit Wind 2015 Pro Forma 107.5 MW
Operating Revenues						
Sales						
Sales for Resale						
Other						
Total Revenues	-	-	-	-	-	-
Operating Expenses						
Operation and Maintenance						
Cost of Fuel and Purchased Power (Reagent)			$270,119	$113,216	$4,299	
Other O & M		$118,313	-	36,455	79,402	713,516
Total O & M	$0	118,313	270,119	149,671	83,701	713,516
Depreciation	91,727	148,974	760,072	152,396	245,304	2,833,457
Taxes other than Income	-	-	-	-	-	112,051
Current Income Tax	(1,103,533)	(1,233,507)	(3,568,891)	(319,322)	(226,206)	(7,325,750)
Deferred Income Tax	1,067,404	1,128,229	3,163,125	200,345	96,619	3,348,083
Total Expense	55,598	162,009	624,425	183,090	199,418	(318,643)
Operating Income	**($55,598)**	**($162,009)**	**($624,425)**	**($183,090)**	**($199,418)**	**$318,643**
Electric Plant in Service	$5,963,484	$6,066,181	$21,841,157	$3,663,366	$9,812,164	$56,669,131
Accumulated Reserve for Depreciation	45,864	120,351	760,072	152,396	245,304	2,833,457
Net Electric Plan in Service	5,917,620	5,945,830	21,081,085	3,510,970	9,566,860	53,835,674
Additions						
Materials and Supplies						
Fuel Stocks						
Prepayments						
Unamorized Loss on Debt						
Decommissioning of Retired Plants						
Provisions for Pension and Benefits						
Provisions for Injuries and Damages						
Total Additions	-	-	-	-	-	-
Total Before Deductions	5,917,620	5,945,830	21,081,085	3,510,970	9,566,860	53,835,674
Deductions						
Accumulated Deferred Income Taxes	1,067,404	1,128,229	3,163,125	200,345	96,619	3,348,083
Customer Advances						
Total Deductions	1,067,404	1,128,229	3,163,125	200,345	96,619	3,348,083
Total Average Rate Base	**4,850,216**	**4,817,601**	**$17,917,960**	**$3,310,625**	**$9,470,241**	**$50,487,591**
Rate of Return	-1.146%	-3.363%	-3.485%	-5.530%	-2.106%	0.631%
Required Return	7.588%	7.588%	7.588%	7.588%	7.588%	7.588%
Operating Income Required to earn 7.588%	$368,034	$365,560	$1,359,615	$251,210	$718,602	$3,830,998
Increase in Operating Income Required to earn 7.588%	$423,632	$527,569	$1,984,040	$434,300	$918,020	$3,512,355
Revenue Multiplier	1.654790	1.654788	1.654789	1.654789	1.654789	1.654789
Required Revenue Increase to earn 7.588%	**$701,022**	**$873,015**	**$3,283,168**	**$718,675**	**$1,519,129**	**$5,812,207**
Reduced F&PP costs resulting from Wind Generation						**($3,275,354)**
Required Revenue Increase to earn 7.588% - Net of F&PP savings						**$2,526,997**

Response No. PSC-071
Attachment A
Page 1 of 1