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

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

October 8, 2015

Mr. Will Rosquist
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
Helena, MT 59620

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

Dear Ms. Whitney:

Enclosed please find Montana-Dakota Utilities Co.'s responses to the Montana Public Service Commission data request dated September 23, 2015. Data request PSC-029 remains outstanding.

Sincerely,

Tamie A Aberle

Tamie A. Aberle
Director of Regulatory Affairs

Attachments
cc: Service List

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

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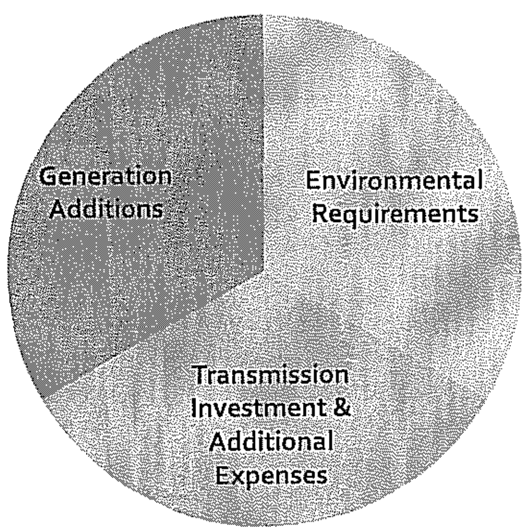
MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
DATA REQUEST
DATED SEPTEMBER 23, 2015
DOCKET NO. D2015.6.51

PSC-009
Regarding: Identifying least cost resources
Witness: Kivisto, pp. 4-8

Among the primary drivers of MDU's $11.8 million per year revenue increase request, you identify generating plant modifications needed to comply with air quality regulations and indicate that costs associated with those plant modifications account for 32 percent of the requested increase. Provide the percentage contributions of the other primary drivers you discuss: generating plant additions needed to serve load, such as Thunder Spirit, Lewis & Clark RICE units, and Hesket III; and transmission investments and impacts from the WAPA/Basin move to SPP.

Response:

The revenue increase is generally attributable as 1/3 to each of the primary drivers of the rate case:



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

PSC-010
Regarding: Identifying least cost resources
Witness: Skabo, p. 3

For each of the listed resources identified through the Integrated Resource Planning process, specify which Integrated Resource Plan(s) (IRP) identified the resource as a "best" option.

Response:

Heskett III	2011 IRP
Lewis & Clark RICE	2013 IRP
Thunder Spirit Wind	2013 and 2015 IRP

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

PSC-011
Regarding: MATS
Witness: Skabo, p. 7

a. **Confirm that the reagent expense impact on variable production costs were accounted for in prior IRP modeling and in the 2015 IRP analysis.**

b. **Quantify the impact of the reagent expenses on the per unit production costs of the affected plants.**

Response:

a. In the 2011 IRP, a sensitivity was ran to include a variable O&M cost to all coal plants to include the potential effects of MATS. This sensitivity was the High Environmental Cost.

   The 2013 IRP added variable O&M costs to the Big Stone AQCS project in 2015 to include reagent cost to control mercury. The Lewis and Clark Baghouse project added an additional variable O&M cost starting in 2015 to meet the MATS standard. The Lewis and Clark plant had historical reagent costs included in the variable O&M cost to meet the mercury standards in Montana. No other units had any additional costs added to their variable O&M costs to meet the MATS standard.

   The 2015 IRP had the same adder for variable O&M cost for the reagent costs as the 2013 IRP for the Big Stone AQCS project. The remaining coal plants had the reagent costs for MATS included in the base variable O&M based on historical costs.

b. The 2011 IRP sensitivity used a $1.25/MWh adder to the variable cost to include the additional costs to comply with the MATS rule.

   In the 2013 and 2015 IRP, an adder of $2.19/MWh for reagent costs was added to Big Stone AQCS project to meet the regional haze and MATS standards, which about $0.82/MWh would be the activated carbon cost to meet the MATS standard.

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

PSC-012
Regarding: Regional Haze Rule
Witness: Skabo, p. 10

a. **Identify the alternatives and their associated costs that the Big Stone owners compared to the construction and operation costs of Big Stone with AQCS.**

b. **Provide a copy the owners' analysis of the alternatives to the construction and operation costs of Big Stone with AQCS.**

c. **Provide a copy of the South Dakota Regional Haze SIP.**

Response:

a. After conducting a thorough analysis of pollution control options, the South Dakota Department of Environment and Natural Resources (SD DENR) determined the control technologies required in the AQCS project. In addition to the AQCS Project, the Big Stone Owners did consider repowering the Big Stone boiler with natural gas; retiring/replacing Big Stone with a combined cycle gas turbine plant; and retiring/replacing Big Stone with a combined cycle gas turbine plant and purchased wind power. The estimated levelized energy costs for the alternatives are included in Attachment A, which includes Joint Exhibit 2 – REASONABLENESS OF BIG STONE AQCS PROJECT, pages 13 - 14 and Attachment 9 OTTER TAIL POWER COMPANY BSP PRO FORMA RESULTS LETTER REPORT NORTH DAKOTA. Both of these documents were provided in the North Dakota PSC Application for An Advance Determination of Prudence Big Stone Air Quality Control System Project Case No. PU-11-163.

b. Please see Response No. PSC-012a.

c. Please see the enclosed CD for Attachment B which includes the South Dakota Regional Haze SIP, including Attachments A through E of the SD RH SIP. Attachments F through I of the SD RH SIP are not included as the referenced attachments address decisions on other utilities' facilities.

Response No. PSC-012
Attachment A

II. Joint Exhibit 2 - REASONABLENESS OF BIG STONE AQCS PROJECT

The South Dakota DENR is the state agency responsible for implementing federal CAA requirements to reduce emissions that may contribute to regional haze from emitting facilities located in South Dakota, including the Big Stone Plant. After conducting a thorough analysis of pollution control options, the DENR determined that the control technologies in the AQCS Project must be required. As a result, the Big Stone Plant Co-Owners must design, construct, install and operate the AQCS by the compliance deadline established by the DENR, or the Plant will not be able to continue operation.

OTP, on behalf of the Co-Owners, has prepared an assessment of alternative scenarios that may be available to respond to the anticipated environmental regulations.[28] OTP developed four response scenarios and evaluated the comparative costs under each scenario using a 20-year levelized cost analysis:

1. Implementing the Big Stone AQCS Project, as Co-Owners have proposed;
2. Repowering Big Stone boiler with natural gas;
3. Retiring/Replacing Big Stone with a CCGT Plant; and
4. Retiring/Replacing Big Stone with a CCGT Plant and purchased wind power.

As shown in Table 2, the AQCS Project is the most economical scenario under all analyses in the Base Case.[29] The analysis of these alternative scenarios was carried out for a Base Case, which also considered the anticipated environmental costs for mercury control and coal ash disposal, as well as the cost of the stranded asset if one of the retirement/replacement options were to be implemented. Table 2 below presents a comparison of the alternative scenarios under the Base Case analysis, including an analysis that incorporates the cost to cover the stranded asset costs ("Stranded Asset Cost Scenario"), and an analysis that includes an additional $5 million in capital cost and $2 million in annual O & M cost for mercury removal and $6.66 million in annual O & M cost for handling coal ash if it is characterized as a hazardous waste ("High Environmental Cost Scenario").

Table 2 – Estimated Levelized Energy Cost (2016$/MWh)

	Big Stone + AQCS	CCGT + Wind	CCGT	Big Stone with Natural Gas
Combined Levelized Energy Cost - (Base Case)	$74.38	$100.43	$103.38	$117.25
Total Energy Cost Including	$74.38	$104.24	$107.19	$117.25

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28 Response scenarios that would not be available in the required timeframe, or could not replace the characteristics that Big Stone provides were not further analyzed. The selection of response scenarios that may be viable is fully explained in Joint Exhibit 3.

29 Attachment 9 (Big Stone Pro Forma Economic Analysis) at 5-6.

Stranded Asset Cost				
Total Energy Cost Including High Environmental Costs	$78.04	$100.43	$103.38	$117.25

The Base Case analysis comparing installation of the AQCS with various options for repowering or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with the cost of the other options at least $26 per MWh or 35% higher than the levelized MWh cost of the proposed AQCS.[30] The AQCS remains the most cost-effective option under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%), and O & M cost (+/-20%).

[30] Attachment 9 at 6.

PUBLIC DOCUMENT - TRADE SECRET - PRIVATE DATA HAS BEEN EXCISED

ATTACHMENT 9

OTTER TAIL POWER COMPANY
BSP PRO FORMA RESULTS LETTER REPORT
NORTH DAKOTA

Burns & McDonnell SINCE 1898

March 29, 2011

Mr. Mark Rolfes
Manager, Generation Development
Otter Tail Power Corporation
215 South Cascade Street
Fergus Falls, MN 56538

Re: Big Stone Plant Pro Forma Economic Analysis – Modeling Results
BMcD Project No. 57975

Dear Mr. Rolfes:

Burns & McDonnell (BMcD) has been retained by Otter Tail Electric Power Company (Otter Tail) to perform a pro forma economic analysis (Analysis) of the air quality control system (AQCS) proposed to be installed on the existing Big Stone Plant (BSP). The AQCS option will be compared to several alternatives for providing energy from a generation resource other than BSP. The Analysis includes preparing a pro forma economic model for each of the following cases.

- BSP with AQCS
- BSP Retrofitted to Burn Natural Gas (BSP on NG)
- A Combined Cycle Plant to Replace BSP (CCGT)
- A Combined Cycle Plant Combined with Wind Energy Purchases to Match the BSP Energy Production (CCGT + Wind)

Screening level pro forma economic models were prepared to determine the levelized cost of power for each alternative over a 20 year planning period. These levelized energy costs can be compared to one another to determine the relative economic attractiveness of each of the options under consideration.

Modeling Inputs

The following inputs were provided to BMcD from Otter Tail's recently filed Integrated Resource Plan (IRP).

- O&M Inflation — 3.0% per annum
- Capital Cost Inflation — 4.0% per annum

[TRADE SECRET DATA BEGINS...

- Interest Rate
- Return on Equity
- Discount Rate

...TRADE SECRET DATA ENDS]

Mr. Mark Rolfes
Otter Tail Power Corporation
March 29, 2011
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[TRADE SECRET DATA BEGINS...

- Market Price of Wind Power (2009 $, excluding PTC)

...TRADE SECRET DATA ENDS]

- Fuel Cost Forecast — Table 1

[TRADE SECRET DATA BEGINS...

...TRADE SECRET DATA ENDS]

The following inputs were provided to BMcD based on Otter Tail's internal estimates for the BSP options.

- BSP with AQCS
  - Net Plant Output — 475 MW
  - Net Plant Heat Rate — 10,715 Btu/kW
  - Net Plant Capacity Factor — 75%
  - Capital Cost of AQCS (2016 $) — $490 million

Mr. Mark Rolfes
Otter Tail Power Corporation
March 29, 2011
Page 3

- Annual O&M Cost (Fixed & Variable 2016 $) — $27.3 million

- BSP on NG
  - Net Plant Output — 475 MW
  - Net Plant Heat Rate — 10,023 Btu/kW
  - Net Plant Capacity Factor — 75%
  - Conversion Capital Cost (2016 $) — $147 million
  - Annual O&M Cost (Fixed & Variable 2016 $) — $13.0 million
- CCGT and CCGT + Wind
  - BSP Decommissioning Cost (2016 $) — $21.3 million
- All Natural Gas Fired Options
  - Linear Facility Capital Cost (2016 $) — $120 million

The following inputs were developed by BMcD from recent project experience.

- CCGT
  - Net Plant Output — 475 MW
  - Net Plant Heat Rate — 6,680 Btu/kW
  - Net Plant Capacity Factor — 75%
  - Capital Cost (2010 $) — $402 million
  - Annual Fixed O&M Cost (2010 $) — $8.50/kW-year
  - Annual Variable O&M Cost (2010 $) — $4.30/MWh
- CCGT + Wind
  - Combined Cycle Net Plant Output — 475 MW
  - Combined Cycle Net Plant Heat Rate — 6,680 Btu/kW

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o Combined Cycle Net Plant Capacity Factor	35%
o Combined Cycle Capital Cost (2010 $)	$402 million
o Combined Cycle Annual Fixed O&M Cost (2010 $)	$8.50/kW-year
o Combined Cycle Annual Variable O&M Cost (2010 $)	$4.30/MWh
o Capacity Factor of Wind Purchases	40%
o Levelized Value of Production Tax Credit (PTC) (2009$)	$20/MWh

The combined cycle cost estimates and performance values presented above for the CCGT and CCGT + Wind options are based on recent project experience. These values are based on a typical cost for an unfired 2 on 1 GE FA.05 combined cycle plant. Although a plant of this type will have an output in the range of approximately 600 MW, only the first 475 MW of capacity was considered in this Analysis, in order to compare the options on a consistent basis. The total capital cost presented above was calculated based on the dollar per kilowatt installed cost of an unfired 2 on 1 GE FA.05 combined cycle plant, multiplied by 475 MW. The heat rate values presented above are based on typical unfired 2 on 1 GE FA.05 combined cycle plant performance. The annual fixed O&M and variable O&M values are also based on typical unfired 2 on 1 GE FA.05 combined cycle plant costs and the variable O&M values included major maintenance costs.

The capacity factor for wind purchases considered in the Analysis is based on an assumed capacity factor for a typical wind farm in this region of the country. The levelized value of the PTC used in the analysis is based on the current legislation and the impact to the levelized cost of power for a typical wind farm, based on recent project experience.

Base Case Results

Each of the alternatives listed above was evaluated in a pro forma economic model to determine a screening level energy cost. These costs can be compared to determine the relative economic attractiveness of each of the alternatives considered.

The capital and O&M costs for BSP with AQCS and BSP on NG were provided to BMcD by Otter Tail in 2016 dollars. These values were input directly into the model without additional escalation applied, other than annual O&M escalation for year to year operations. The year to year escalation rate of three percent was used consistent with Otter Tail's IRP filing.

Capital and O&M costs for the CCGT option were taken from recent BMcD experience. These values were developed in 2010 dollars, and were escalated four percent per year for capital and three percent per year for O&M to 2016 dollars, consistent with Otter Tail's IRP modeling assumptions.

In the CCGT + Wind case, BMcD estimated that a 40% capacity factor could be provided by market wind energy purchases. The $71/MWh cost of market wind energy purchases in 2009 dollar provided by Otter Tail was used as a starting point to determine the price of market wind energy to use in this Analysis. The CCGT + Wind option evaluated in the base case included the value of the PTC. No option was considered in the base case without the PTC. A value of the PTC of $20/MWh in 2009 dollars was deducted from the market wind energy purchases price to arrive at a 2009 cost of wind power of $51/MWh including the value of the PTC. This value was escalated by four percent per year to 2016 dollars resulting in a levelized market price of wind energy of $67.11 to use in the economic modeling. The remaining energy would be produced by a combined cycle plant. For purposes of this Analysis, a 475 MW combined cycle plant was utilized, equivalent to BSP. This facility would operate at a 35 percent capacity factor to achieve an annual energy production equivalent to BSP. Current combustion turbine technology results in combined cycle plant net capacities in the range of 615 MW. The capital cost in this Analysis was based on the dollar per kilowatt estimates from for a 615 MW facility, assuming that Otter Tail would own a 475 MW share in a facility of this size.

For each of the alternatives to BSP with AQCS, $120 million was added to cover the costs of linear facilities required to support the project. This would cover the costs to run a new natural gas line to the BSP plant to convert the units to burn natural gas or construct a new combined cycle plant at that site. Alternatively, if a new combined cycle facility were to be constructed at another site, linear infrastructure would need to be constructed for natural gas, transmission service, and possibly water and discharge pipelines.

For the CCGT and CCGT + Wind options a cost of $21.3 million was also added to the capital costs to cover the decommissioning costs for BSP.

In addition to the decommissioning costs, Otter Tail estimated that an $82 million cost should be assigned to the CCGT and CCGT + Wind options to cover stranded asset costs if BSP would cease to operate. This cost represents the current book value of BSP. However, the economic modeling for the BSP with AQCS and BSP on NG options does not account for this remaining book value to be depreciated going forward. The BSP with AQCS and BSP on NG options only account for the capital cost to add the new AQCS equipment or to convert to fire with natural gas. The stranded asset cost was not included in the base case values, however this cost was

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modeled as an additional scenario to determine the impact it would have on the energy cost. It was determined that this scenario would add \$3.81/MWh to the levelized energy cost for the CCGT and CCGT + Wind options.

Otter Tail also requested that BMcD consider the impact of a high environmental cost scenario. This scenario consists of the inclusion of mercury emissions control requirements and potential ash regulations. Otter Tail provided a \$5 million additional capital cost and \$2 million per year additional O&M cost to be included for mercury removal on the BSP with AQCS option. Also, \$6.66 million in additional O&M was provided for handing ash if it is categorized as a hazardous waste. These three additional costs resulted in a \$3.66/MWh increase in the levelized cost of energy for the BSP with AQCS option.

The results of the modeling using the base case assumptions are provided in Table 2 below.

Table 2 – Economic Modeling Base Case Results

20-YEAR LEVELIZED BUSBAR COSTS		BSP + AQCS	CCGT + Wind with PTC	CCGT	BSP on NG
Operations Summary					
Net Dispatchable Capacity (MW)		475	475	475	475
Net Dispatchable Generation Capacity Factor		75%	35%	75%	75%
Net Dispatchable Energy Generation (MWh)		3,120,750	1,456,350	3,120,750	3,120,750
Net Wind Capacity Factor		-	40%	-	-
Net Wind Energy Market Purchases (MWh)		-	1,664,400	-	-
Capital Cost (2016 \$)		\$ 490,000,000	\$ 621,289,115	\$ 621,289,115	\$ 267,000,000
Depreciation & Interest Basis Energy Costs					
Fuel	(2016\$ / MWh)	\$ 40.68	\$ 66.44	\$ 66.44	\$ 99.70
O&M	(2016\$ / MWh)	\$ 12.09	\$ 13.37	\$ 9.55	\$ 5.78
Depreciation	(2016\$ / MWh)	\$ 8.56	\$ 23.25	\$ 10.85	\$ 4.66
Return	(2016\$ / MWh)	\$ 6.10	\$ 16.58	\$ 7.74	\$ 3.32
Interest	(2016\$ / MWh)	\$ 4.91	\$ 13.34	\$ 6.22	\$ 2.68
Income Taxes	(2016\$ / MWh)	\$ 2.03	\$ 5.53	\$ 2.58	\$ 1.11
Levelized Revenue Requirement	**(2016\$ / MWh)**	**\$ 74.38**	**\$ 138.50**	**\$ 103.38**	**\$ 117.25**
Cost of Wind Energy	**(2016\$ / MWh)**	**\$ -**	**\$ 67.11**	**\$ -**	**\$ -**
Combined Levelized Energy Cost	**(2016\$ / MWh)**	**\$ 74.38**	**\$ 100.43**	**\$ 103.38**	**\$ 117.25**
Stranded Asset Cost Scenario Adder	**(2016\$ / MWh)**	**\$ -**	**\$ 3.81**	**\$ 3.81**	**\$ -**
Total Energy Cost Including Stranded Asset Cost	**(2016\$ / MWh)**	**\$ 74.38**	**\$ 104.24**	**\$ 107.19**	**\$ 117.25**
High Environmental Cost Scenario Adder	**(2016\$ / MWh)**	**\$ 3.66**	**\$ -**	**\$ -**	**\$ -**
Total Energy Cost Including High Environmental Cost	**(2016\$ / MWh)**	**\$ 78.04**	**\$ 100.43**	**\$ 103.38**	**\$ 117.25**

Based on the results of the base case Analysis presented above, BSP with AQCS is the most economically attractive alternative under the base case assumptions. The second most attractive

Mr. Mark Rolfes
Otter Tail Power Corporation
March 29, 2011
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alternative is the CCGT + Wind option, however, this option results in a 35 percent higher cost of energy than BSP with AQCS. Adding in the stranded asset costs to the CCGT + Wind option increases the differential in cost of energy between these two options to 40 percent. Adding in the high environmental cost scenario adder reduces these differentials in levelized energy costs to 29 percent and 34 percent respectively.

Sensitivity Analysis

A sensitivity analysis was prepared for each of the alternatives evaluated in the Analysis under the following cases:

- Capital Cost (plus or minus 30%)
- Fuel Cost (plus or minus 20%)
- O&M Costs (plus or minus 20%)

A sensitivity analysis was performed to determine the impact of changes to the capital costs of each option. The results of the capital cost sensitivity analysis are presented in Figure 1 below.

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Otter Tail Power Corporation
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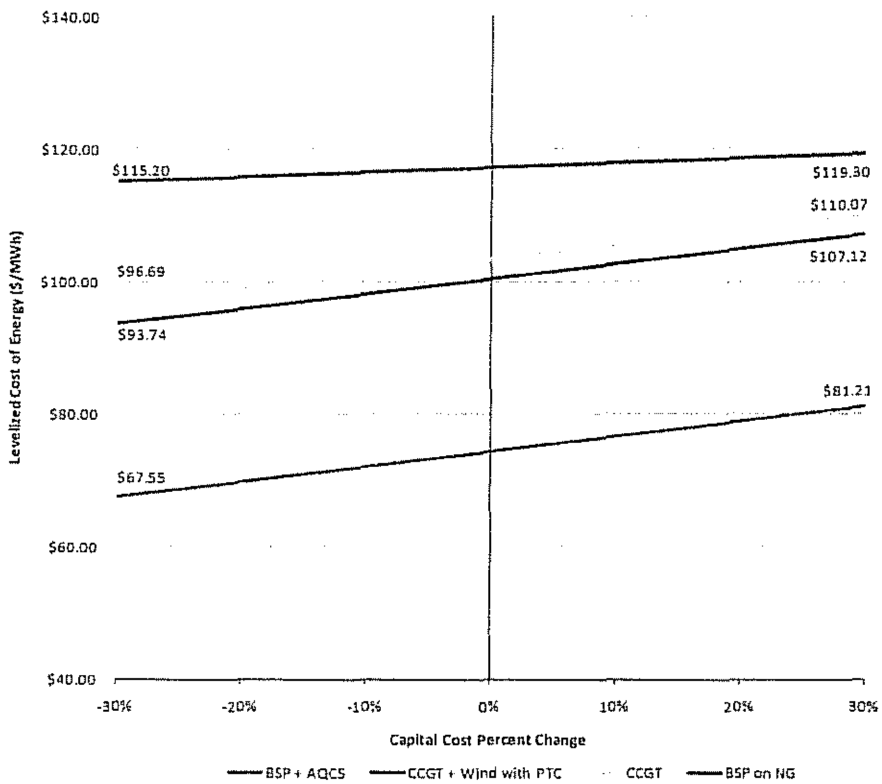
Figure 1 – Capital Cost Sensitivity Levelized Energy Costs



Over the range of capital costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Capital cost changes have a similar impact on BSP with AQCS, CCGT and CCGT + Wind options, since they all have relatively similar capital costs. Capital cost changes have the least impact on the BSP on NG option, since it requires the least capital cost investment.

A sensitivity analysis was performed to determine the impact of changes to the fuel costs for each option. The results of the fuel cost sensitivity analysis are presented in Figure 2 below.

Mr. Mark Rolfes
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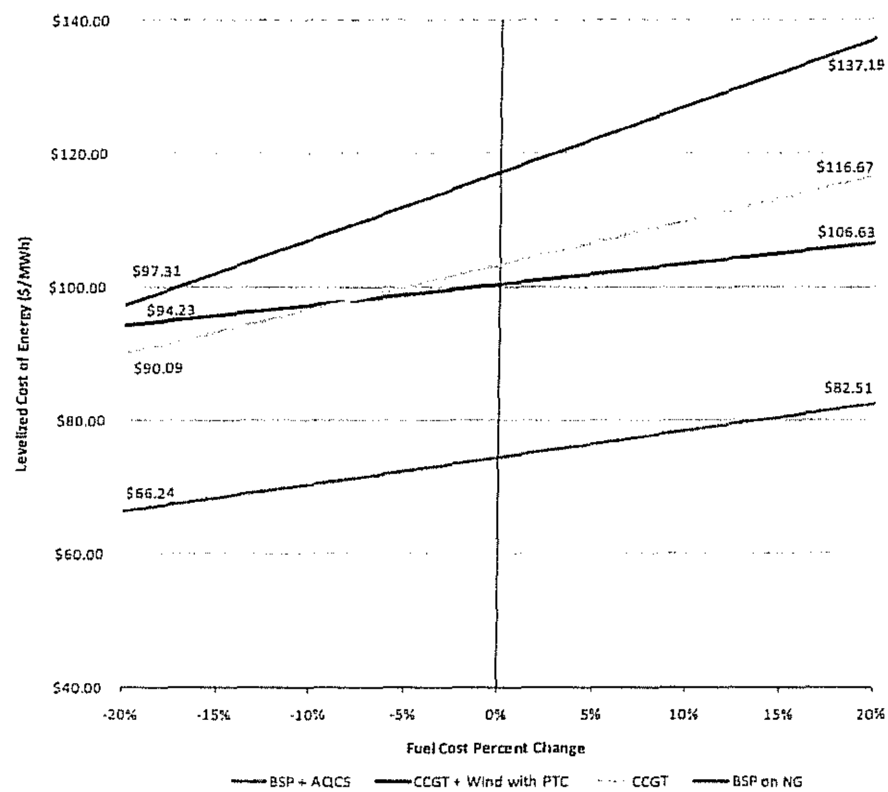
Figure 2 – Fuel Cost Sensitivity Levelized Energy Costs



Over the range of fuel costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Fuel cost changes have the largest impact on the natural gas-fired options, since natural gas has a much higher base case cost than coal. The impact or fuel cost changes is reduced on the CCGT + Wind case, since more than half of the energy in that case is provided from wind power generation, which is unaffected by changes in fuel prices.

A sensitivity analysis was performed to determine the impact of changes in O&M costs for each of the options. The results of the O&M cost sensitivity analysis are presented in Figure 3 below.

Mr. Mark Rolfes
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March 29, 2011
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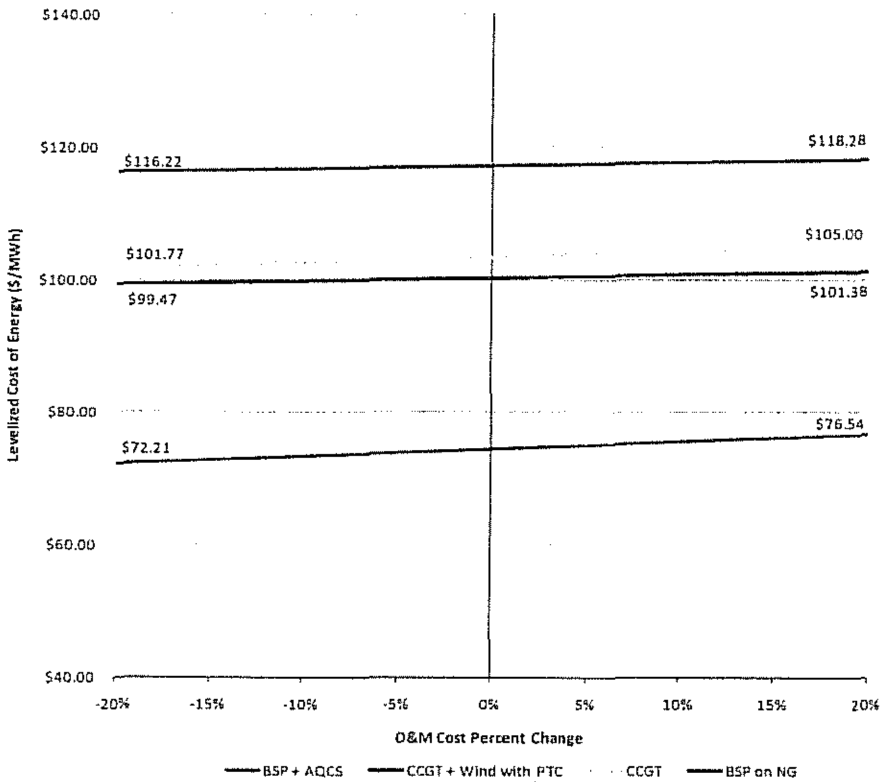
Figure 3 – O&M Cost Sensitivity Levelized Energy Costs



Over the range of O&M costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. O&M cost changes have relatively insignificant impacts on all of the options considered.

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Conclusions

Based on the results of this Analysis, the BSP with AQCS is the most economically attractive alternative of the options considered for BSP under the potential future scenarios evaluated. The BSP with AQCS option results in a significantly lower levelized cost of energy than the other options evaluated under the base case assumptions. BSP with AQCS option remains economically attractive relative to the other options considered over the range of sensitivities evaluated in this Analysis.

The impact on other Otter Tail resources and Otter Tail's integrated resource plan (IRP) was not evaluated in this Analysis. Otter Tail will need to determine how a change of resource type at the BSP site would impact other resources in Otter Tail's generation portfolio, as well as how a new resource would fit into Otter Tail's IRP.

If you have any questions regarding the results of this Analysis, please call Jeff Greig at 816-822-3392 or Jeff Kopp at 816-822-4239 to discuss.

Sincerely,

Jeff Greig
General Manager, Business & Technology Services

Jeffrey T Kopp

Jeff Kopp, PE
Development Engineer

JTK

cc: Mark Rolfes

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

PSC-013
Regarding: Big Stone AQCS
Witness: Skabo, p. 11-12.

a. **Provide a copy of the North Dakota Public Service Commission Order accepting the AQCS project as prudent.**

b. **Provide the 2011 IRP cost effectiveness analyses of the AQCS project.**

c. **Provide the results of the additional modeling that determined that the AQCS project remained a least cost option even if the plant was only able to run through 2019. Clarify whether the analysis was included in an IRP filed with the Montana Public Service Commission.**

Response:

a. Please see Attachment A.

b. Please see Attachment B on the enclosed CD for the Company's 2011 Montana IRP Volumes I through IV.

c. Please see Attachment C. Attachment C was not filed as part of the Company's IRP.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Montana-Dakota Utilities Co. **Case No. PU-11-163**
Advance Determination of Prudence – Big Stone Air Application

Otter Tail Power Company **Case No. PU-11-165**
Advance Determination of Prudence – Big Stone Air Application

FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER

MAY 9, 2012

Appearances

Commissioners Tony Clark, Brian P. Kalk, and Kevin Cramer.

Mark Bring, Associate General Counsel, 215 S. Cascade St., Fergus Falls, MN 56538-0496, appearing on behalf of Otter Tail Power Company.

B. Andrew Brown, Dorsey & Whitney LLP, Suite 1500, Minneapolis, MN 55402 on behalf of Otter Tail Power Company and Montana-Dakota Utilities Co.

Mark Gruman, Public Service Commission, State Capitol, 600 E. Boulevard Av., Bismarck, North Dakota 58505, on behalf of the Public Service Commission advocacy staff.

Illona Jeffcoat-Sacco, General Counsel, Public Service Commission, State Capitol, 600 E. Boulevard Av., Bismarck, North Dakota 58505, on behalf of the Public Service Commission advisory staff.

Daniel S. Kuntz, Associate General Counsel, P.O. Box 5650, 1200 West Century Avenue, Bismarck, ND 58506-5650, appearing on behalf of Montana-Dakota Utilities Co.

Al Wahl, Administrative Law Judge, Office of Administrative Hearings, 1701 North Ninth Street, Bismarck, North Dakota 58501-1882.

Preliminary Statement

On May 20, 2011, Applicants Montana-Dakota Utilities Co. (Montana-Dakota) and Otter Tail Power Company (Otter Tail) filed separate applications with the North Dakota Public Service Commission (Commission) seeking an advance determination of prudence (ADP) under North Dakota Century Code § 49-05-16 for a proposed Air Quality Control System project (AQCS) at the Big Stone Plant (Big Stone).

On July 27, 2011, the Commission issued a Notice of Filing and Notice of Intervention deadline of September 2, 2011. No parties intervened in these proceedings.

On September 7, 2011, the Commission issued a Notice of Consolidated Hearing for November 29, 2011. The Notice specified the issue to be considered was whether the proposed AQCS resource addition is prudent.

The Commission held the consolidated hearing on the applications on November 29, 2011 in the Commission Hearing Room, 12th floor, State Capitol, Bismarck, North Dakota.

On January 9, 2012, Montana-Dakota, Otter Tail, and Public Service Commission Advocacy Staff filed a Settlement Agreement.

On January 27, 2012, the Commission issued a Notice of Opportunity for Hearing on the Settlement Agreement providing until March 7, 2012 for comments or requests for hearings. No comments or requests for hearing were received.

Having allowed all interested persons an opportunity to be heard and having heard, reviewed and considered all testimony and evidence presented, the Commission makes the following:

Findings of Fact

1. Otter Tail is an investor-owned electric utility headquartered in Fergus Falls, Minnesota authorized to provide public utility service in North Dakota.

2. Montana-Dakota is an investor-owned electric utility headquartered in Bismarck, North Dakota authorized to provide public utility service in North Dakota.

3. The Big Stone Plant (Big Stone) is a coal-fired power plant located approximately 2.5 miles northwest of Big Stone City in Grant County, South Dakota, near the Minnesota-South Dakota border. Big Stone has a single cyclone fired boiler that burns low sulfur Powder River Basin coal. Big Stone is rated at 495 MW gross electricity generation and 475 MW net electricity generation.

4. Big Stone has three investor-owned utility co-owners. NorthWestern Energy owns a 23.4% share, Montana-Dakota owns a 22.7%, and Otter Tail owns 53.9% and serves as Big Stone's operating agent.

5. Big Stone is the largest baseload resource for each of the co-owners and provides electricity to their customers in North Dakota, South Dakota, Minnesota, and Montana. Only Otter Tail and Montana-Dakota serve North Dakota customers.

I. Clean Air Act

A. *Regional Haze*

6. The federal Clean Air Act, 42 U.S.C. § 7479, mandates a national goal of remedying and preventing visibility impairment from man-made air pollution in specified Class I areas of the United States. Class I areas include 156 national parks and wilderness areas.

7. The Environmental Protection Agency (EPA) promulgated the Regional Haze Rule in 1999 (49 CFR Part 51), and a revised rule in 2005 to implement the Clean Air Act's requirement of improving visibility in Class I areas. The Regional Haze Rule includes the requirement to procure, install and operate Best Available Retrofit Technology (BART) on major generating sources, including existing electric generating units that were placed into operation between 1962 and 1977. Big Stone began commercial operation on May 1, 1975.

8. Under the Regional Haze Rule, state environmental agencies are authorized to submit a State Implementation Plan (SIP) to EPA. Absent state action, EPA must adopt a plan that addresses existing emissions from sources within the state that contribute to regional haze, with the goal of no man-made visibility impairment in Class I areas by 2064.

9. Otter Tail performed an evaluation to determine the visibility impact of its existing operations on seven Class I areas that are located in Michigan, Minnesota, North Dakota, and South Dakota. Based on the results, the South Dakota Department of Environment and Natural Resources (South Dakota DENR) determined that Big Stone emissions contribute to an impairment of visibility in multiple Class I areas and is therefore subject to BART.

10. On September 15, 2010, the South Dakota DENR, Board of Minerals and Environment adopted a South Dakota Regional Haze Rule, Administrative Rules of South Dakota chapter 74:36:21. The South Dakota Regional Haze Rule imposed emission limits for three pollutants that contribute to regional haze. The South Dakota Regional Haze Rule limits nitrogen oxides to 0.10 lb/mmBtu, compared to 0.86 lb/mmBtu in the current permit, sulfur dioxides to 0.09 lb/mmBtu, compared to 3.0 lb/mmBtu in the current permit, and particulate matter to 0.012 lb/mmBtu, compared to 0.26 lb/mmBtu in the current permit.

11. Under the South Dakota Regional Haze Rule, Big Stone must achieve BART compliance expeditiously but no later than five years after EPA's approval of the South Dakota SIP.

12. During the South Dakota rulemaking process, Otter Tail recommended that selective non-catalytic reduction technology (SNCR) combined with separated overfire air be used to reduce NOx.

13. On January 21, 2011, the South Dakota DENR submitted the South Dakota SIP to the EPA. The South Dakota SIP proposed the following technologies for Big Stone:

- selective catalytic reduction technology (SCR) with separated overfire air for control of NOx.
- Semi-dry flue gas desulfurization for control of SO_2.
- Baghouse for control of particulate matter.

14. On March 29, 2012, the EPA approved the South Dakota SIP with publication of the final rule in the Federal Register to follow. The final rule was published in the Federal Register on April 26, 2012.

B. *Mercury Control*

15. The 1990 Amendments to the Clean Air Act required EPA to study the effects of emissions of specified hazardous air pollutants by electric steam generating plants, including mercury emissions. EPA commenced rulemaking to control mercury under the Maximum Achievable Control Technology (MACT) provision of the Clean Air Act, § 112, and the agency published the proposed Mercury and Air Toxics Standards (often referred to as Utility MACT) in the May 3, 2011 Federal Register. The EPA finalized the Utility MACT on December 21, 2011 and published the rule in the February 16, 2012 Federal Register.

16. Utilities have three years to achieve compliance with the Utility MACT.

II. Resource Analysis for Big Stone

17. The Big Stone AQCS Project consists of a semi-dry flue gas desulphurization (FGD) system with for control of SO_2, selective catalytic reduction technology (SCR) with separated overfire air for control of NOx, a new baghouse for control of particulate matter, and activated carbon injection (ACI) for control of mercury emissions.

18. North Dakota Century Code § 49-05-16 provides that a public utility that intends to make a resource addition (including modification of a generation facility) may file an application with the Public Service Commission for an advance determination that the resource addition is prudent.

19. The applicants presented a cost estimate prepared by the engineering firm Sargent & Lundy for the AQCS project, excluding the ACI of $489,397,400 in 2015 dollars, with an accuracy of plus or minus 20 percent. Applicants estimated an additional cost of installation of the ACI for mercury control of $5,012,700. The AQCS cost estimate total of $494,410,100 includes engineering, procurement, construction, supervision, and management costs for the project.

20. Sargent & Lundy compared the cost estimate to similar projects that Sargent & Lundy has completed; and to available industry data, adjusted for plant size and year in-service. Sargent & Lundy compared scope, quantities, equipment, labor hours, and costs in the cost estimate for the AQCS project to other similar projects. Sargent & Lundy believes the cost estimate is consistent with other comparable projects.

21. The Applicants considered coal, hydropower, nuclear as options for retiring Big Stone. Hydropower and nuclear generation were rejected due to current statutory restrictions or because they could not be available in the time frame required for BART compliance.

22. The Applicants assessed the comparative construction and operation costs of Big Stone with AQCS to three natural gas alternatives: conversion of the Big Stone Plant boiler to natural gas, construction of a new 475 MW combined cycle gas turbine (CCGT), and construction of a new 475 MW CCGT and purchased wind energy. The analysis concluded Big Stone with the AQCS was the least-cost option.

23. The Applicants considered a gas-fired combustion turbine and a heat-recovery boiler at the Big Stone site, and the use of that steam generation to power the existing Plant turbine. Approximately two-thirds of the generation would come from the new gas-fired generation and one-third would come from the existing steam turbine. Using the one-third to two-third ratio, the generation from Big Stone would be required to increase from 475 MW to 1,425 MW. This additional generation would overload available transmission and thus could not be available before the AQCS Project's compliance deadline. Due to the time delay, the mismatch of resources and the high cost for such a sizeable gas plant, this response scenario was not further evaluated.

24. The Applicants considered repowering the existing Big Stone Plant with biomass, but the AQCS would still be required.

25. Burns & McDonnell's levelized cost analysis demonstrated the Big Stone Plant with the AQCS is the most economic scenario. The levelized cost for Big Stone with the AQCS is $70.89/MWh (2016 dollars). The next most cost-effective option, the CCGT plus wind energy purchases, is $100.43/MWh (2016 dollars), which is 42% more expensive than the AQCS option.

26. Sensitivity analyses were performed for the AQCS and each of the alternatives for capital costs (plus or minus 30%), fuel costs (plus or minus 20%), and O&M costs (plus or minus 20%). The analyses demonstrated that the AQCS remained the least cost option over the range of sensitivities evaluated by a significant margin.

27. Otter Tail conducted Strategist modeling to identify the least-cost suite of generation resources in terms of Net Present Value of Revenue Requirements for the 15-year planning period 2011-2025.

28. In 21 of 22 scenarios modeled, Strategist selected the Big Stone Plant with the AQCS project as a part of the least cost resource plan. The only scenario in which the Big Stone Plant was not selected in the resource mix was one where unlimited market purchases were allowed, based on the capacity and energy price forecasts included in the IRP. This resulted in 450 MW of capacity being purchased from the market.

29. Montana-Dakota separately analyzed the cost effectiveness of the Big Stone AQCS project as part of its 2011 IRP submitted to the Commission on May 12, 2011. Montana-Dakota modeled the AQCS project as a resource addition beginning in 2015. The AQCS was compared with other alternative to determine if it would be more cost-effective to retire the Plant or install the AQCS to allow for its continued operation.

30. Montana-Dakota modeled sensitivity scenarios consisting of assumptions regarding higher capital costs for both the AQCS project and combustion turbines. In the AQCS scenario, the project cost was incrementally increased to determine at what point other alternatives would be preferred. With the modeled cost of the AQCS project nearly doubled from the original estimated cost, the project was still selected as part of Montana-Dakota's resource plan recommended in its 2011 IRP.

31. Commission Advocacy Staff testified that participating in the MISO market as an alternative to generation from the Big Stone Plant would subject the Applicants' ratepayers to too great a risk of market fluctuations.

32. Commission advocacy staff witness Richard Hahn also testified that the proposed AQCS project is cost effective and is the preferred option as compared to the reasonable alternatives.

33. Based on the Burns & McDonnell levelized cost analysis, the Applicants' respective analysis, and analysis by Advocacy Staff, the Commission finds that the continued operation of Big Stone is prudent and a least cost alternative to securing alternative generation.

34. Applicants' Exhibit 111 is the South Dakota SIP. As testified by Applicants' witness, Terry Graumann, Table 6-14 on page 95 of Exhibit 111 represents the deciview visibility impairment contribution for each control technology Otter Tail included in its BART process. OTP recommended option #6 (SNCR) to South Dakota, however, South Dakota selected option #8 (SCR). We note that for options # 6, #7 and #8, each deciview visibility impairment is less than 0.5, the EPA threshold. Mr. Graumann further testified that South Dakota's DENR cost-effectiveness test was $900 per ton, and options #6, #7 and #8 are less than $900 per ton.

35. In response to questions from Commissioner Clark on Exhibit 111, Mr. Graumann agreed that despite the decision by South Dakota that SCR represented BART, the visibility improvement by employing SCR as opposed to SNCR could be imperceptible.

36. Exhibit 111 also discloses a capital cost differential of $69,900,000 between employment of option #6, SCR, and option #8, SNCR. The Commission notes that the difference in cost between the two technologies is less than the difference in the accuracy differentials in Applicants' cost estimate for SCR, that is plus or minus 20 percent, or plus or minus $97,879,480.

37. The Commission makes no finding regarding the prudence of the air quality control technologies proposed by the applicants. Nothing in this order states or implies the Commission is determining the prudence of any particular air quality control technology. Given the cost difference in the technologies and the insignificant difference in visibility improvement between the technologies, the Commission chooses not to bind a future Commission on the question of the prudence of one air quality control technology compared to another. That question is best left to a future proceeding in which rate recovery is requested.

From the foregoing Findings of Fact, the Commission makes the following:

Conclusions of Law

1. The Commission has jurisdiction in this matter.

2. In comparison to generation alternatives, the continued operation of the Big Stone Plant is prudent.

From the foregoing Findings of Fact and Conclusions of Law, the Commission makes its:

Order

The Commission orders that the Applicants' requests for an advance determination of prudence for their proposed participation in the Big Stone AQCS project are hereby granted subject to the following conditions:

1. No determination is made in this order regarding the prudence of using either SCR or SNCR technology in the AQCS.

2. The Applicants shall submit semi-annual reports to the Commission, beginning in June 2012, and continuing through June 2017, regarding the amounts and types of costs incurred with respect to the AQCS project, and any changed circumstances that will materially affect the cost, schedule or installation of the AQCS project.

3. Consistent with subsection 6 of North Dakota Century Code § 49-05-16, the Applicants must be prepared to demonstrate in subsequent rate recovery proceedings the reasonableness of all costs incurred or obligated to implement the AQCS project. The Applicants must also be prepared to demonstrate in subsequent rate recovery proceedings that any costs incurred, other than AFUDC, the AQCS were prudently incurred.

PUBLIC SERVICE COMMISSION

Kevin Cramer	**Tony Clark**	**Brian P. Kalk**
Commissioner	**Chairman**	**Commissioner**

Updated Big Stone AQCS Analysis

5/13/2015	Optimal Resource Case - Big Stone AQCS	4 year life Big Stone AQCS (2016-2019)	3-No Big Stone after 2015
2013			
2014			
2015	LCBH,2-WIND_PPA,2-WSCT	LCBH,2-WIND_PPA,2-WSCT	LCBH,2-WIND_PPA,2-WSCT
2016			3-WSCT
2017	WSCT	WSCT	WSCT
2018			
2019			
2020	CC-200	CC-200	CC-200
2021			
2022		CT-72	
2023			
2024			
2025			
2026			
2027			
2028			
2029			
2030		CC-129	
2031			
2032	WIND20		
NPV	$3,515.55	$3,612.65	$3,668.54
Difference	-	2.76%	4.35%

*All cost are in 2012 dollars

LCBH - Lewis & Clark Baghouse(~$27.4 million)

WSCT- 36.6MW Wartsila18V50SG Combustion Turbine(~$955/kW or $33.2 million)

WIND_PPA - 25MW blocks

CC-200 - 200MW of a potential partnership of a 560MW GE7FA.05(Combined Cycle 2x1) ($828/kW)

CT72 - 71.6MW GE 7EA Combustion Turbine (~759/kW or $54.4 million)

CC-129 - 129MW Combined Cycle of GE 7EA(incremental increase of~$648/kW or ~$83.6 million)

WIND20 - 20 MW of self-built wind

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

PSC-014
Regarding: Summer and winter peaks
Witness: Neigum, p. 4, Exhibit_(DJN-1)

a. **Exhibit_(DJN-1) appears to indicate that the difference between the summer and winter peaks narrowed starting in about 2008. Is current growth in winter peak demand significantly different, statistically, than growth in summer peak demand? If so, what accounts for the difference and what are the resource planning implications?**

b. **Provide MDU's adjusted 50/50 peak winter load in 2014.**

c. **How would MDU's current least-cost resource plan and system operations change if MDU expected to transition from summer-peaking to winter-peaking?**

d. **If MDU were to transition to winter peaking, would MISO's determination of MDU's peak load obligations change?**

Response:

a. Montana-Dakota separately forecasts the 50/50 summer and winter peak demands. Under MISO's current Resource Adequacy Construct, Montana-Dakota only needs to meet its summer 50/50 peak demand requirements and therefore the resource planning process is based on upon summer only requirements.

b. Montana-Dakota does not weather normalize its actual peak winter demands as there are a number of independent variables which impact the adjustment. The Company's '2014-2033 Electric Load Forecast' estimated a 50/50 winter peak demand of 558 MW.

c. No change. See response to PSC-014a.

d. No change. See response to PSC-014a.

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

PSC-015
Regarding: Summer and winter peaks
Witness: Neigum, p. 5

a. **Describe the pricing and terms of the 2012, 2013, and 2014 WE Energies annual capacity purchase agreements. In particular, identify any quality differences in the capacity obtained through such purchases and an owned capacity resource such as the Hesket III gas combustion turbine.**

b. **Clarify whether the WE Energies capacity purchase agreements were three separate resource acquisitions, as shown on p. 5, or a single, three-year agreement, as described on p. 7.**

c. **Are capacity purchase agreements such as the WE Energies agreements available for longer time periods, e.g., 5, 10, or 15 years? Explain the basis for your answer.**

d. **Describe why MDU continues to plan for and acquire generating plants to supply its retail customers despite being a member of MISO. Discuss MISO's function(s) and how those functions affect MDU's approach to integrated resource planning.**

Response:

a. We Energies Contract:

6/1/12 – 5/31/13	110 MWs	$2,900 per MWmonth
6/1/13 – 5/31/14	115 MWs	$2,900 per MWmonth
6/1/14 – 5/31/15	120 MWs	$2,900 per MWmonth

Through the We Energies contract, Montana-Dakota was given the day ahead dispatch option to an equivalent 13,500 mmbtu/kwh simple cycle gas turbine located at the WEC.S MISO CP pricing node in Wisconsin with the natural gas price indexed to the Midpoint of the ANR ML7 Daily Index.

b. Single, three year agreement

c. The availability of longer term capacity purchase agreements depends on available resources and suppliers options at the time a request for proposal is released. In the Company's 2009 RFP, We Energies was only able to offer a three year pricing agreement. In the Company's

2010 RFP, We Energies was only able to offer its wholesale tariff rate as a proposal which was subject to annual adjustments.

d. Resource adequacy is still subjected to state rights and authority. MISO offers capacity sharing and footprint diversity to its members through its resource adequacy construct (Module E) and an annual capacity market for excess capacity and customer shortages. Availability and pricing of annual capacity is subject to availability. There is no guarantee of available capacity or pricing and is subject to change every year. Montana-Dakota considers short-term capacity purchases from the MISO capacity market as an option for meeting small capacity needs.

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

PSC-016
Regarding: June 2010 RFP for energy and capacity resource
Witness: Neigum, p. 7

Provide the June 2010 RFP and the analysis of bids and alternative supply side resources available to MDU as part of its 2011 IRP.

Response:

Please see Attachment A for the June 2010 RFP.
Please see Attachment B for the analysis of bids.

Response No. PSC-016
Attachment A

Montana-Dakota Utilities Co.

Request for Proposal for Capacity and Energy Supply

June 1, 2010

Table of Contents

1. INTRODUCTION

1.1. Purpose

Montana-Dakota Utilities Co., a Division of MDU Resources Group Inc. ("Montana-Dakota"), is a public utility with retail electric load in parts of North Dakota, South Dakota, Montana, and Wyoming. During the normal course of its business operations, Montana-Dakota routinely evaluates alternatives to fulfill its need to maintain reliable and cost-efficient capacity and energy resources for its customers.

In this Request for Proposal ("RFP"), Montana-Dakota requests competitive proposals ("Proposals") for capacity and energy totaling at least 25 megawatts (MW) and no more than 225 MW for a period of at least five years, with five-year extension options available, beginning power deliveries between June 1, 2015 and May 31, 2020. Persons or entities responding to this RFP are referred to as "Respondents."

1.2. Product Description and Requirements

For reliability purposes, Montana-Dakota is seeking Proposals involving the purchase of capacity and energy resources for a term of at least five years, with five year extension options available, beginning with deliveries to begin between June 1, 2015 and May 31, 2020. To meet Montana-Dakota's summer peak requirements, preference will be given to Proposals that have the ability to be dispatched with load-following capabilities.

All capacity and energy offered in a Proposal must be delivered to Montana-Dakota's Integrated System, which consists of its service territories in North Dakota, South Dakota, and Montana, in order to serve Montana-Dakota retail customers. Bid pricing should reflect the capacity and energy at the designated delivery point and include all costs to deliver the capacity and energy to such delivery point. Proposals must be for generating capacity of at least 25 MW and no more than 225 MW. Montana-Dakota strongly prefers unit-specific Proposals that involve a full unit at a single site for which Montana-Dakota will have full scheduling and dispatch authority. Montana-Dakota also prefers automatic generation control functionality in order to meet its load-following requirements.

Montana-Dakota encourages Respondents to provide Proposals for summer and non-summer capacity and/or energy if the Respondent believes its Proposal can provide an economic benefit to Montana-Dakota customers. For the purpose of this RFP, summer capacity months refer to the period of June through September.

Montana-Dakota will consider all Proposals that meet the aforementioned requirements. Montana-Dakota will evaluate the reliability, cost and customer rate impacts of all Proposals.

No proposed Power Purchase Agreements (PPA) of a term shorter than five years will be considered in this RFP.

If a Proposal involves a generating resource not yet fully operational, in addition to the other requirements outlined in this section, the Respondent must provide Montana-Dakota with sufficient data to establish that the proposed generating resource will achieve the commercial operation date designated in the Proposal, and at that date will be fully capable of producing the capacity and energy stated in the Proposal. The Proposal must provide an overview and detailed description of the proposed generating resource, including status of any and all necessary permits and regulatory approvals, in a separate attachment as part of the Respondent's response package.

Montana-Dakota reserves the right to require additional information not identified in this RFP in order to fully evaluate the costs and impacts of any Proposal.

1.3. Changes to RFP, Schedules, and Addenda

Montana-Dakota reserves the right to unilaterally revise or suspend the schedule, or terminate this RFP process at its sole discretion without liability to any Respondent.

2. BID SUBMITTAL

2.1. General Instructions

Montana-Dakota's Official Contact for this RFP is:

Mr. Hoa Nguyen
Montana-Dakota Utilities Co.
400 North 4th Street
Bismarck, ND 58501
Phone: 701-222-7656
Fax: 701-222-7872
E-mail: hoa.nguyen@mdu.com

Respondents should meet all the terms and conditions of the RFP to be eligible to compete in the RFP process. Respondents should follow all instructions contained in the RFP and submit all relevant documents. It is the Respondent's responsibility to advise the Official Contact of any conflicting requirements, omissions of information, or the need for clarification before Proposals are due. Respondents should clearly organize and identify all information submitted in their Proposals to facilitate review and evaluation. Failure to provide all the information requested in the RFP process or failure to demonstrate that the Proposal satisfies all of the Montana-Dakota requirements will be grounds for disqualification. Prior to the short-listing of Proposals, all correspondence and communications from the Respondent to Montana-Dakota must be made in writing through the Official Contact.

2.2. Respondent's Qualifications

Montana-Dakota will consider Proposals from any qualified Respondent, including electric utilities (e.g., investor-owned, municipal, cooperative, or tribal), independent power producers, qualified developers of generating resources (including renewable resources, distributed generation, and demand-side management (DSM) resources), and power marketers.

Each Respondent shall respond fully and accurately to the Statement of Financial Conditions and Creditworthiness Qualifications included in Exhibit A to the RFP. In addition to that information, during the Proposal review process, Montana-Dakota may require each Respondent to provide further credit and financial information in order to assist Montana-Dakota in addressing and weighing the creditworthiness of each Respondent.

Montana-Dakota invites Proposals from all potential suppliers who are capable of meeting the conditions of the RFP, and Montana-Dakota will evaluate all responsive bids.

2.3. RFP Communications

Prior to the proposal submission deadline, all communications should be directed to the Official Contact's e-mail. Based upon the nature and frequency of the questions Montana-Dakota receives, Montana-Dakota will choose to either respond to individuals directly or address the question through the bidder's conference (see Section 2.5).

2.4. Schedule

The following schedule and deadlines apply to this RFP:

ACTIVITY	DATE*
Issue RFP	June 1, 2010
Bidder's Conference	July 8, 2010
Notice of Intent to Bid Due	July 23, 2010
RFP Responses Due	August 20, 2010
Shortlist Notification	October 1, 2010
Selection Process Complete	November 15, 2010

* Dates may be advanced or delayed at Montana-Dakota's sole discretion. The Respondents will be notified if the dates are changed.

2.5. Bidder's Conference

Montana-Dakota currently plans on conducting a bidder's conference for interested Respondents:

Time:	9:00 am Central Time
Date:	July 8, 2010
Location:	Montana-Dakota Utilities Co. 400 North 4th Street Bismarck, ND 58501

Prospective Respondents who plan on attending the conference should RSVP to the Official Contact's e-mail. Please provide names, titles, and phone numbers of the individuals who will be attending and a brief description of the Respondent's proposed project if possible. The purpose of the bidder's conference is to allow potential Respondents the opportunity to ask questions and seek clarification about the RFP process. To make the meeting as productive and informative as possible, Respondents are encouraged to submit any questions in writing prior to the conference. Attendance is not required for submitting a Proposal, but the bidder's conference will serve as a forum to clarify any preliminary issues regarding the RFP.

Teleconferencing capabilities will be available be for prospective Respondents that RSVP to the Official Contact's e-mail.

2.6. Notice of Intent to Bid (NOIB)

In order to identify persons or entities interested in submitting a Proposal, and to assure that all those having such an interest receive any subsequent information distributed in the RFP process, interested parties are requested to submit via e-mail or facsimile, a non-binding NOIB by **July 23, 2010**. The form for the NOIB is included in Exhibit B to this RFP.

2.7. Proposal Submittal Fee

A non-refundable fee of one thousand dollars ($1,000.00) per bid per Respondent will be required in order to qualify the Proposal(s) for consideration. The fee should be payable in a check made out to "Montana-Dakota Utilities Co." Proposal submittal fees must be paid by the bid submittal deadline (see Section 2.8.2).

2.8. Proposal Content and Submission Instructions

2.8.1 In addition to the information described elsewhere in this RFP, all Respondents must include as part of their Proposal all relevant information requested in the response package. Proposals that do not contain all required information or do not fully reflect the bid requirements may not be considered at Montana-Dakota's sole discretion. In addition to the required information, the Respondents should include with their Proposals any other information that may be needed for a thorough understanding and evaluation of their Proposals.

2.8.2 Complete Proposals, including all exhibits, must be received by **August 20, 2010** by Montana-Dakota's Official Contact. Montana-Dakota will accept Proposals delivered by the U.S. Postal service, express delivery services, personal hand delivery, or electronic means such as e-mail and facsimile. Electronic submittals must be immediately followed by the hard copy of the original response package. Only sealed Proposals will be accepted. On the envelope, Respondent shall indicate "*Response to Montana-Dakota RFP re. Capacity and Energy Supply Resources.*"

2.8.3 All Proposal terms, conditions, and pricing should be valid through the completion of the selection process, currently planned for **December 31, 2010**. Any accepted Proposal will become binding in accordance with the executed definitive agreement (Section 4.3) and after the Regulatory Approval Process (Section 4.4).

2.8.4 Respondents will be notified by **October 1, 2010** if their Proposal has been selected for the short-list and subsequent negotiation. Respondents with

Proposals not selected for the short-list will be notified. None of the material received by Montana-Dakota from Respondents in response to this RFP will be returned. All Proposals and exhibits will become the property of Montana-Dakota, subject to the confidentiality provisions of Section 2.9.

2.8.5 Prices and dollar figures must be stated in U.S. Dollars of which the base year must be specified.

2.9. Confidentiality

With each Proposal, Montana-Dakota will require all parties to sign the Confidentiality Agreement, contained in Exhibit C to this RFP. Montana-Dakota will sign and execute the Confidentiality Agreement upon receipt from each Respondent. Montana-Dakota will use commercially reasonable efforts, in a manner consistent with the Confidentiality Agreement, to protect any claimed proprietary and confidential information contained in a Proposal, provided that such information is clearly identified by the Respondent as "PROPRIETARY AND CONFIDENTIAL" on the page on which proprietary and confidential material appears.

2.10. Requirements of the Proposals

2.10.1 Proposals should be provided in the format outlined in Section 2.10. Montana-Dakota requests that all exhibits, documents, schedules, etc. submitted as a part of a proposal be clearly labeled and organized in a fashion that facilitates easy location and review.

2.10.2 All proposals must conform, as applicable, to the requirements in this RFP.

2.10.3 Proposals must be for the sale to, and purchase by Montana-Dakota, of a firm, unit-contingent supply of capacity and energy, and/or system participation capacity and energy. The proposals must identify the resource and location supplying the capacity and any special regulatory status that may be claimed.

2.10.4 A single Respondent may submit more than one proposal.

2.10.5 The pricing, as set forth in Section 2.10.11.5, contained in each proposal shall reflect all present applicable state and federal environmental regulations and requirements. Montana-Dakota reserves the right to estimate the impacts of future environmental regulations on the Proposal. Montana-Dakota will not be responsible for any "stranded costs" that the Respondent may incur, but are not identified in the proposal. Any exit fees must be explicitly stated in the Proposal.

2.10.6 Proposals that rely upon supply resources located outside of the Montana-Dakota system must provide for the delivery of the full capacity amount to Montana-Dakota's system.

2.10.7 Transmission service that the Respondent acquires for the purpose of delivering said capacity should be Firm, Point-to-Point, or Network service.

Said transmission service shall be continuously reserved for the duration of the capacity transaction. If Firm, Point-to-Point, or Network Transmission service is not obtained prior to the time the Respondent submits his proposal, the burden will be on the Respondent to identify all known fixed and variable cost for delivery to Montana-Dakota's system as well as any known transmission constraints.

2.10.8 The Respondent shall be responsible for the providing and contracting of all transmission related services for delivery to the Montana-Dakota system. At some point during the evaluation process, Montana-Dakota, in its sole discretion, will require a Respondent to demonstrate the ability to acquire transmission services if necessary. If the Respondent is unable or fails to demonstrate such ability to obtain transmission services, or if obtaining such service requires system upgrade or interconnection costs that Montana-Dakota, in its sole discretion, determines to be excessive, Montana-Dakota may terminate further consideration of the Proposal.

2.10.9 Proposals should address any contractual and operational constraints such as cycling, minimum load, minimum run time, minimum down time, start-up fees, etc., that the Respondent intends to impose in his proposal.

2.10.10 Prior to Montana-Dakota signing a power purchase agreement, the Respondent will be required to provide evidence of credit assurance as detailed in Section 2.10.11.9 of this RFP. Montana-Dakota will approve all forms of credit assurance before entering into the agreement.

2.10.11 All Proposals must include the following minimum components in the order provided:

2.10.11.1 "Executive summary" which indicates the highlights and special features of the Proposal including a description of the source for the capacity and energy.

2.10.11.2 Statement from the Respondent which indicates the time period during which the proposal will remain in effect, but no sooner than December 31, 2010.

2.10.11.3 Comprehensive listing and description, including a rationale if warranted, of all contract terms and conditions that the Respondent would seek during contract negotiations.

2.10.11.4 Listing of any economic, operational, or system conditions (including sensitivities to anticipated dispatch levels) that might affect the Respondent's ability to deliver capacity and energy, as proposed. Proposals should address any contractual and operational constraints, such as cycling, minimum load, minimum run time, minimum down time, and start-up fees, that the Respondent intends to impose in its proposal.

2.10.11.5 Information on the cost of the capacity and energy shall be provided including:

2.10.11.5.1 Designated delivery point.

2.10.11.5.2 Firm price bid. The capacity price must be fixed for the time period(s) quoted and the energy price must be either fixed or based on known and measurable indices.

2.10.11.5.3 In addition to a firm price bid, the Respondent may submit alternative non-firm price bids. However, these bids must specifically describe the risks that the Respondent is passing on to Montana-Dakota and its customers.

2.10.11.5.4 The Respondent should specify the basis (i.e., annually, quarterly, monthly, etc.) and type of all payments it expects to receive. In the case of a fully dispatchable generating resource, such payments might include start-up payments ($/start) or spinning and supplemental reserve payments ($/operating hour).

2.10.11.5.5 As applicable, the Proposal should include all formulas that will be used to calculate the full capacity and energy rate, or any other rate that the Respondent may specify, with all its respective components well defined. A sample calculation illustrating the application of each formula is also required.

2.10.11.5.6 The Respondent must provide a printed schedule projecting for each contract year, quarter, or month, as appropriate, depending upon how frequently the Respondent's rate(s) or its respective components will be updated, for the full term of the proposed contract of the following:

a. Full capacity rate and all components ($/kW-month, etc.).
b. Contract capacity amount in MW at the delivery point for which the Respondent is expected to provide its estimated Unforced Capacity (UCAP) amount according to Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO or MISO) definition.
c. Capacity payment ($/month).
d. Total energy rate and all its components ($/MWh).
e. Projected values of any independent variables (e.g., fuel price, heat rates, operating hours, and number of starts) that are to be used in the calculation of payments.

f. Sufficient information to allow Montana-Dakota to replicate this proposed contract term data.
g. Any proposed revisions to the pricing scheme if the Respondent intends to offer a contract extension option.

2.10.11.6 Information on the makeup of the Respondent's Company and its parent organization shall be provided along with the most current annual financial report, most recent audited financial report, and SEC Form 10-K.

2.10.11.7 Site locations of the proposed projects and other drawings that are helpful in describing projects shall be included.

2.10.11.8 The Respondent must certify that any identified generating resource is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.

2.10.11.9 Montana-Dakota requires secure and reliable physical delivery of the capacity and associated energy corresponding to all proposals. Security and reliability of physical delivery will be guaranteed by either (1) contractual credit assurance by a third party, (2) corporation commitment accompanied by an investment level credit rating from a major rating agency, or (3) combinations of 1 and 2. All forms of credit assurance will be approved by Montana-Dakota before entering into a power purchase agreement. (Credit Assurances shall include a letter of credit or performance bonds for an amount equal to the costs associated with one year of the contract or as mutually agreed.)

2.10.11.10 The Respondent must certify that it has or will have all necessary permits in effect for the identified generating unit. The Respondent shall provide a description of the resource's ability to comply with all presently applicable and anticipated environmental regulations and requirements and any additional environmental benefits that the resource would, or presently does, afford; a listing of expected emissions (as applicable) and the status of all permit applications; and a listing of any and all potential and known environmental liabilities that may be associated with the project or its site.

2.10.11.11 Montana-Dakota prefers Proposals offering full dispatchability of energy for all hours during the term of the contract. This would permit Montana-Dakota to schedule quantities of energy, from a minimum of zero to a maximum equal to the quantity stated in the Proposal on an hour-by-hour basis. Montana-Dakota prefers to have the option of connecting the proposed generating resources to its automatic generation control system, but dispatchability is not a requirement.

2.10.12 Montana-Dakota encourages Respondents to provide Proposals for summer and non-summer capacity and energy if the Respondent believes its Proposal can provide an economic benefit to Montana-Dakota and its customers. For the purpose of this RFP, summer capacity months refer to the period of June through September.

2.10.13 Proposals for variable capacity resources such as wind, solar, run-of-river hydro, landfill gas, and anaerobic digestion should provide, for each calendar month, a schedule of expected capacity factors, maximum capacity, and hourly capacity (for each hour of the month).

2.10.14 Proposals for DSM resources such as demand-response programs and energy efficiency programs should provide, for each calendar month, a schedule of expected capacity factors, maximum capacity, and hourly capacity (for each hour of the month).

2.10.15 Montana-Dakota will entertain Proposals which contain the provision for an asset sale or option for an asset sale from the Respondent to Montana-Dakota as part of the Respondent's bid.

3. EVALUATION PROCESS

3.1. Proposal Review

3.1.1. Price will be a major factor in Montana-Dakota's evaluation, with due consideration given to dispatchability, operational performance, reliability, deliverability, credit, environmental impacts, contract terms, and other factors. Respondents shall include sufficient detail to evaluate all costs associated with the Proposal(s). To ensure that Proposals will provide customer benefits, Montana-Dakota will compare Proposals with the benefits, including costs and reliability, of alternative resource scenarios. Proposals will also be compared and evaluated in terms of other non-price characteristics; therefore, the lowest price submittal may not necessarily be selected. The evaluation of Proposals will be based on the information provided by the Respondent and available industry information, with special emphasis on Montana-Dakota being able to provide reliable service and maximize the economic value to its customers. Montana-Dakota shall evaluate all Proposals in terms of price and non-price attributes and reject any Proposal that, at Montana-Dakota's sole discretion,

a) Does not meet the minimum requirements set forth in the RFP;

b) Is not economically competitive with other Proposals or resource alternatives;

c) Is submitted by the Respondent who is determined by Montana-Dakota to have insufficient creditworthiness, insufficient financial resources and/or insufficient technical qualifications to provide dependable or reliable service; or

d) Fails to meet the resource and reliability needs of Montana-Dakota.

In order to assess the feasibility and viability of the Proposals, the evaluation will determine the technical, physical and operational capability of the applicable generating resources to meet the operating parameters specified in the Proposal. Such technical analysis will include, but not be limited to, a review of transmission access (including existing transmission contracts), fuel access and transportation (including existing fuel contracts), environmental conditions, certification and permit conditions and/or restrictions, unit location, maintenance history and schedules, and operational flexibility and history.

3.1.2. Montana-Dakota shall evaluate responsive Proposals and select for further review and negotiation a Proposal or Proposals, if any, that Montana-Dakota believes provides the greatest value to its customers. In the event negotiations with a Respondent or Respondents do not produce a final and fully executed contract satisfactory to Montana-Dakota, Montana-Dakota reserves the right to pursue any and all other resource options available to it.

3.1.3. Montana-Dakota intends to compare system impacts of short-listed Proposals against the system impacts from new-build alternatives in determining the appropriate purchases and/or acquisitions for Montana-Dakota's future capacity and energy needs.

3.1.4. Montana-Dakota reserves the right to accept or reject any or all Proposals for any reason at any time after submittal without explanation to the Respondent, or to make an award at any time to a Respondent who, in the sole opinion and discretion of Montana-Dakota, provides a Proposal Montana-Dakota deems favorable. Montana-Dakota also reserves the right to make an award to other than the lowest price Respondent, if Montana-Dakota determines that to do so would result in the greatest value to its customers.

3.1.5. All renewable resources, distributed generation and DSM are invited to compete in this RFP process and will be evaluated in a consistent manner with all other bids, with consideration given to projections as to their life-cycle costs, operational compatibility, reliability, and availability.

3.1.6. Those Respondents who submit Proposals do so without legal recourse against Montana-Dakota or its directors, management, employees, agents, or contractors, based on Montana-Dakota's rejection, in whole or in part, of their

Proposal or for failure to execute any agreement tendered by Montana-Dakota. Montana-Dakota shall not be liable to any Respondent or to any other party, in law or equity, for any reason whatsoever relating to Montana-Dakota's acts or omissions arising out of or in connection with the RFP.

3.1.7. If a selected Proposal involves a generating resource not yet operational, the Respondent must provide Montana-Dakota with a full financial guarantee, including performance bonds and/or letters of credit, up to the level of product commitments and in an amount and at a level determined by Montana-Dakota in its sole discretion, expressly including replacement capacity and energy costs and any related penalty fees, in the event the generating resource does not become commercially operational as scheduled.

3.1.8. In reviewing and considering Proposals, Montana-Dakota will analyze potential credit and risk concerns in any comparison of Proposals. As part of its detailed evaluation phase, Montana-Dakota will specifically weigh the credit- and risk-related factors and costs underlying each of the Proposals. To conduct this review, Montana-Dakota requires that each Respondent include with its response package a detailed description of the proposed credit support. The pricing provided shall expressly include the costs of such credit support. Montana-Dakota will review and assess the sufficiency and adequacy of the proposed credit support, and if Montana-Dakota, at its sole discretion, determines such credit support is insufficient, it shall assess additional costs and/or expenses to the evaluation of such a Proposal.

3.1.9. Selection and elimination of Proposals and subsequent notification of Respondents at all stages of the evaluation will remain entirely at Montana-Dakota's discretion.

3.1.10 Montana-Dakota reserves the right to award multiple contracts if combinations of proposals provide the lowest overall cost and the highest level of reliability.

3.2. Proposal Threshold Requirements

The Respondent should provide complete and accurate information to ensure that its Proposal satisfies the Threshold Requirements listed below. Montana-Dakota, at its sole discretion, may reject a Proposal for further consideration if the Proposal fails to meet the Threshold Requirements or provides incomplete and/or inaccurate responses. Montana-Dakota may seek clarification and/or remedy of a Proposal.

3.2.1. General Threshold Requirements

a. The Proposal is received on time and complies with the submission instructions.

b. The Proposal is bona fide, and the Respondent (or its guarantor) has sufficient financial capacity to support the Proposal.

c. Complete and accurate answers are provided to all questions in the RFP.

d. The Proposal Submittal Fee is included.

e. The proposed capacity and associated energy are available and deliverable to Montana-Dakota's Integrated System no later than June 1, 2015.

f. The proposed capacity is at least 25 MW and no more than 225 MW.

g. If a PPA, the proposed term is for a minimum of five years.

3.2.2. Operating Performance Thresholds

a. The Respondent must certify that it has or will have all necessary permits in effect for the identified generating resource.

b. The Respondent must certify that any identified generating resource is or will be built and maintained in good working order, free of material defects, and has been and will be operated in accordance with good utility practice and applicable maintenance schedules and in compliance with all applicable laws and regulations.

c. Montana-Dakota prefers the identified generating resource be fully dispatchable and has an automatic generation control that is tied into Montana-Dakota's Electric Control Center in Bismarck, North Dakota. The costs associated with this installation are the responsibility of the Respondent.

e. If a PPA, the Respondent must be willing to coordinate the generating resource's maintenance scheduling with Montana-Dakota.

3.2.3. Transmission Threshold

a. Deliverability to Montana-Dakota's Integrated System will be taken into account.

b. If the generating resource is or will be located outside of Montana-Dakota's Integrated System, the Respondent must provide a transmission plan for deliverability to wheel the generating resource's power to the Integrated System. Transmission costs to connect with the Integrated System are the responsibility of the Respondent.

c. If the generating resource is not yet in-service, but has a completed Generator Interconnection Study, a copy of this agreement must accompany the Proposal.

d. If the generating resource is not yet in-service and will be interconnected to Montana-Dakota's transmission system, the Respondent must complete an Application for Generator Interconnection Request with the Midwest ISO. A copy of this application must accompany the Proposal.

e. For an unfinished resource, the final agreement between Montana-Dakota and the Respondent will require the Interconnection Study to be completed, or will be contingent upon such a study being completed.

3.3. Screening Process

Montana-Dakota intends to select Proposals that will be included on its short-list by **October 1, 2010**. Through the short-listing process, those Proposals that are inferior to other Proposals in terms of overall cost and level of reliability, at Montana-Dakota's sole discretion, will be eliminated from further consideration. Montana-Dakota will notify all short-listed Respondents that they have been included on the short-list. Similarly, Montana-Dakota intends to notify Respondents of those Proposals that are eliminated from further consideration within a reasonable amount of time.

Montana-Dakota plans to analyze the short-listed Proposals in detail by assessing their impact on its customer electric service rates, comparing their costs to those of other resource alternatives, and examining their compatibility with Montana-Dakota's resource needs.

Montana-Dakota may elect to schedule meetings or conference calls with each short-listed Respondent to review and clarify its Proposal. After the selection of the short-listed Proposals, Montana-Dakota will begin contract negotiations with such Respondent(s).

Montana-Dakota may select a final Respondent(s) based on the detailed evaluation of the short-listed Proposals. This selection will not automatically be based on the lowest price alternatives available amongst the Proposals. The price and non-price attributes described in part in this RFP solicitation document will be considered in their totality for each Proposal. Montana-Dakota will use its sole discretion, judgment and analyses in making the final selection in the RFP process. Montana-Dakota's objective is to select resources that have the potential to offer the maximum reliability and value, based on cost and non-cost attributes.

4. CONTRACTS AND REGULATORY APPROVAL

4.1. General

The Respondent(s) whose Proposal is selected will be responsible for acquiring and verifying that they are in compliance with all necessary licenses, permits, certifications, reporting requirements, and approvals required by federal, state and local government laws, regulations and policies, including if applicable, for the design, construction and operation of the project. In addition, the Respondent shall fully support the regulatory approval process associated with any potential acquisition or power supply arrangement.

The Respondent shall be liable for all, and Montana-Dakota shall not be responsible for any, of the costs that the Respondent incurs to prepare, submit, and negotiate his Proposal, subsequent contract, and any related activity including governmental approvals.

4.2. Contract Modifications

It is anticipated that the contract format for the prospective PPA resulting from this RFP will be based on the Mid-Continent Energy Marketers Association Agreement (MEMA). A copy of the MEMA Agreement is contained in Exhibit D for reference purposes. Respondents may expressly identify and include proposed changes to the MEMA Agreement in their response packages. Such proposed revisions will allow Montana-Dakota to assess the significance and impact of the requested changes to the Proposal. Montana-Dakota reserves the right to utilize a different contract format, based on its sole discretion.

4.3. Definitive Agreement

As soon as practicable after Montana-Dakota completes negotiations, Montana-Dakota expects the selected Respondent(s) to execute a definitive agreement. Failure of the Respondent(s) to promptly execute a definitive written agreement after notification of a winning bid will result in rejection of the Proposal.

4.4. Regulatory Approval Process

At Montana-Dakota's sole discretion, any final negotiated contract may be conditioned upon regulatory actions and approvals by regulatory authorities. All consents and approvals of governmental authorities required for the consummation of the contemplated transactions shall have terms and conditions acceptable to Montana-Dakota.

4.5. Collusion

By submitting a Proposal to Montana-Dakota in response to this RFP, the Respondent certifies that the Respondent has not divulged, discussed, or compared its Proposal with any other Respondents and has not colluded whatsoever with any other Respondents with respect to its Proposals.

Exhibit A – Form of Statement of Financial Conditions and Creditworthiness

The following information shall be completed as appropriate and will be used to assess the applicant's financial conditions and creditworthiness.

1. Company Information

Type of Business

____ Corporation
____ Limited Liability Company
____ Partnership
____ Other (describe)

Applicant Organization

Legal Corporate Name:

Street Address:

City, State, Zip Code:

Dun & Bradstreet Number:

Federal Tax ID Number:

Applicant Credit Contact

Name:

Title:

Phone Number:

Email Address:

For Corporation/Limited Liability Companies

Date and State of Incorporation/Registration:

Street Address:

City, State, Zip Code:

For General Partnerships

Name of General Partner:

Address of General Partner/Registered Agent:

City, State, Zip Code:

2. Guarantor

Guarantor Company

Legal Corporate Name:

Street Address:

City, State, Zip Code:

Dun & Bradstreet Number:

Federal Tax ID Number:

3. Credit Information

The company and/or company's guarantor (if applicable) is required to submit the most recent 2 years of audited financial statements and accompanying notes. Indicate below what statements are being submitted.

____ 10K

____ 8Ks to the extent they address any information set forth in the 10Ks or 10Qs

____ 10Q

____ Other (describe)

All submitted information must be in the English language, and financial data denominated in United States currency, and conform to generally accepted accounting principles (GAAP) in the United States. If the offering entity's financial information is consolidated with other entities, then it is the offering entity's responsibility to extract and submit as separate documents all data and information related solely to the offering entity. This must include all financial information, associated notes and all other information that would comprise a full financial report conforming to GAAP.

Has the offering entity or predecessor company declared bankruptcy in the last 5 years?

____ Yes

____No

Are there any pending bankruptcies or other similar state or federal proceedings, outstanding judgments or pending claims or lawsuits that could affect the solvency of the offering entity?

____ Yes

____No

If the answer is "Yes" to either of the above questions, please provide an addendum to this application describing the situation and how it affects the offering entity's ability to meet or not meet it credit obligations.

Respondent/Guarantor Credit Rating

Standard & Poor's

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

Moody's

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

Fitch

Last Rating Date:

Corporate Rating:

Senior Unsecured Long term Debt Rating:

Other:

In the event the above information is inadequate or fails to completely meet Montana-Dakota's need for financial security for a given bid, the entity must provide evidence of its capability to provide collateral instruments.

Please detail all credit related issues and concerns that Montana-Dakota should be aware of prior to negotiation of a formal power purchase agreement document:

Bank Reference Information

Bank Name:

Street Address:

City, State, Zip Code:

Contact Name:

Phone Number:

Fax Number:

Account Number:

4. Project-specific Information

For project-specific supply proposals, please provide the following information:

Owners and percentage of ownership in generation unit(s):

Amount and source(s) of equity financing:

Amount and terms of financing, including:

- Amount of loan(s)
- Term of loan(s)
- List of conditions
- Amortization schedule

5. Authorization

The Offering Entity hereby represents and warrants that all statements and representations made herein, including any supporting documents, are true to the best of Offering Entity's knowledge and belief. The undersigned authorized official of the Offering Entity warrants that the Offering Entity agrees to be bound by these representations. The Offering Entity authorizes the above listed entities to release data requested by Montana-Dakota necessary to perform a credit check in connection with Offering Entity's interest to bid on this RFP.

Offering Entity's Company Name:______________________________

Signature of Authorized Official:______________________________

Name of Authorized Official (print):____________________________

Title of Authorized Official (print):____________________________

Date Signed:____

Exhibit B – Form of Notice of Intent to Bid

Date: ______________________________

Our organization intends to submit a proposal in response to the Montana-Dakota Utilities Co. Request for Proposals for Capacity and Energy Supply.

Contact Name: ______________________________

Name of Firm: ______________________________

Address: ______________________________

____

Phone: ______________________________

e-mail: ______________________________

Alternate Contact: ______________________________

Address: ______________________________

____

Phone: ______________________________

e-mail: ______________________________

Project Description: ______________________________

____

____

____

____

Signature: ______________________________

Exhibit C – Form of Confidentiality Agreement

MUTUAL CONFIDENTIALITY AGREEMENT

Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., having its principal place of business at 400 North 4th Street, Bismarck, ND 58501 ("Montana-Dakota") and ____________________, having its principal place of business at ________________________________ ("Respondent"), are discussing details related to the Respondent's reply to a Request for Proposal ("RFP") that Montana-Dakota has issued regarding the purchases of capacity and energy dated June 1, 2010. In the course of the discussions about the RFP each party may disclose certain confidential or proprietary information ("Proprietary Information") to the other party.

For purposes of this Mutual Confidentiality Agreement, Proprietary Information shall mean all information, technical data or know-how, whether written, oral, visual, electronic or in any other form (which may include, without limitation, strategic project development plans, financial information, business plans and records, and project information and records,) disclosed, acquired, or generated as a result of or in connection with the RFP process. Proprietary Information shall also include this Mutual Confidentiality Agreement and the terms and conditions set forth herein.

A. In consideration of Montana-Dakota and Respondent agreeing to supply each other Proprietary Information relating to the RFP process and in consideration of both parties entering into the exchange of information and/or discussions relating to the RFP process, Montana-Dakota and Respondent each agree that it, its corporate affiliates, and each of their respective directors, officers, employees, lenders, and professional advisors (each individually "Representatives"):

1. Will keep secret and confidential the Proprietary Information supplied to the other party and any discussions and negotiations about the RFP process except as herein provided and in a manner no less restrictive than the manner that the receiving party protects its own confidential information;

2. Will use the Proprietary Information only for the purpose of participating in, evaluating and negotiating the RFP process;

3. Will disclose the Proprietary Information only to its Representatives who need to know the Proprietary Information for the purpose of participating in, evaluating and negotiating the RFP process;

4. Will not, whether or not the Parties enter into definitive agreements,

disclose to any third party (other than its Representatives) any of the Proprietary Information, other than the Proprietary Information which is in, or independently comes into, the public domain;

5. Will not, engage in any transactions of any kind or description whatsoever with regard to or using the Proprietary Information during the term of this Agreement without the written consent of the other party;

6. Will, if requested in writing, promptly destroy or return any of the Proprietary Information provided without keeping any copies; and

7. Will promptly notify the other party if any of the Proprietary Information conveyed to it is required to be disclosed by reason of law or legal process and will cooperate with the other party regarding any action which the other party (at the other party's sole cost and expense) may elect to take to challenge the legality or validity of such requirement.

B. Montana-Dakota and Respondent also acknowledge and agree:

1. Proprietary Information which is provided will not be considered to be Proprietary information if that information is (i) in the other party's possession prior to disclosure, (ii) is in the public domain prior to disclosure, or (iii) lawfully enters the public domain through no violation of this Mutual Confidentiality Agreement.

2. No agreement for a power purchase agreement or other transaction shall be deemed to exist unless and until a Definitive Transaction Agreement has been executed and delivered by the parties. The term "Definitive Transaction Agreement" does not include this Mutual Confidentiality Agreement, a letter of interest or any other preliminary written agreement, nor does it include any verbal agreement;

3. Neither party makes any representation or warranty regarding the completeness or accuracy of any information provided to the other; any and all such representations and warranties shall be made in a written, executed agreement and will then be subject to the provisions thereof;

4. Money damages would not be a sufficient remedy for a breach of this Mutual Confidentiality Agreement and the injured party is entitled to specific performance and injunctive or other equitable relief and remedies for any breach; such remedies shall not be the exclusive remedies but shall be in addition to all other remedies available at law or in equity;

5. Neither party will make any announcement of the status of the Respondent's reply to the RFP or of any negotiations with respect to a possible power purchase agreement without the prior written consent of the other;

6. This Mutual Confidentiality Agreement is governed by the laws of the state of North Dakota; and

7. The obligations under this Mutual Confidentiality Agreement shall be continuing and shall survive the termination of the RFP process and any discussion or negotiations between the parties, but that all obligations of the parties hereunder will expire two years from the date of this Mutual Confidentiality Agreement.

The parties have executed this Mutual Confidentiality Agreement as of _____________ ___, 2010.

____________________________	MONTANA-DAKOTA UTILITIES CO., a Division of MDU Resources Group, Inc.
By:________________________	By:________________________
Title:______________________	Title:______________________

Exhibit D – Mid-Continent Energy Marketers Association Agreement

MEMA

Mid-Continent Energy Marketers Association

Capacity and Energy Tariff

MID-CONTINENT ENERGY MARKETERS ASSOCIATION
CAPACITY AND ENERGY TARIFF
TABLE OF CONTENTS

ARTICLE ONE: PURPOSE, APPLICABILITY AND GOVERNANCE

1.1 Purpose. The purpose of this Tariff is to provide for sales of Product by MEMA Members.

1.2 Applicability. Services under this Tariff are applicable to MEMA Members.

1.3 Disclaimer. This Tariff was prepared by MEMA to facilitate orderly trading in and development of wholesale power markets. Neither MEMA nor any MEMA Member nor any of their agents, representatives or attorneys shall be responsible for its use, or any damages resulting therefrom. By providing this Tariff MEMA does not offer legal advice and all users are urged to consult their own legal counsel to ensure that their commercial objectives will be achieved and their legal interests are adequately protected.

GENERAL TERMS AND CONDITIONS

ARTICLE TWO: GENERAL DEFINITIONS

2.1 "Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

2.2 "Agreement" means this Tariff, including its exhibits (including but not limited to the Supplementary Agreement attached hereto as Exhibit B), schedules and any written supplements, any collateral, credit support or margin agreement or similar arrangement between the Parties to a Transaction, and all Transactions (including any Confirmations).

2.3 "Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

2.4 "Business Day" means any day except a Saturday, Sunday, a Federal Reserve Bank holiday, or a Canadian Banking holiday where the Buyer or Seller has its principal place of business located in Canada. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

2.5 "Buyer" means the MEMA Member to a Transaction that is obligated to purchase and receive, or cause to be received, the Product, as specified in the Transaction.

2.6 "Call Option" means an Option entitling, but not obligating, the Option Buyer to purchase and receive the Product from the Option Seller at a price equal to the Strike Price for the Delivery Period for which the Option may be exercised, all as specified in the Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller shall be obligated to sell and deliver the Product for the Delivery Period for which the Option has been exercised.

2.7 "Claiming Party" has the meaning set forth in Section 4.3.

2.8 "Claims" means all third party claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Tariff.

2.9 "Confirmation" has the meaning set forth in Section 3.3.

2.10 "Contract Price" means the price in $U.S. (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of the Product, as specified in the Transaction.

2.11 "Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace a Terminated Transaction; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of a Transaction.

2.12 "Credit Rating" means, with respect to a Party (or its Guarantor, if applicable) (i) the rating then assigned to the unsecured, senior long-term debt obligations (not supported by third party credit enhancements) of such entity, or (ii) in the case that such entity does not have a rating for its senior unsecured long-term debt, the rating then assigned as an issuer rating. In either case the rating shall refer to the rating then assigned by S&P, Moody's, or any other rating agency agreed to by the Parties as set forth in the Supplementary Agreement attached hereto as Exhibit B.

2.13 "Defaulting Party" has the meaning set forth in Section 6.1.

2.14 "Delivery Period" means the period of delivery for a Transaction, as specified in the Transaction. "Delivery Point" means the point at which the Product shall be delivered and received, as specified in the Transaction.

2.15 "Downgrade Event" means the downgrade event, if any, as agreed by the Parties in the Credit and Collateral Requirements.

2.16 "Early Termination Date" has the meaning set forth in Section 6.2.

2.17 "Electronic Confirmation" has the meaning set forth in Section 3.4.

2.18 "Equitable Defenses" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

2.19 "Event of Default" has the meaning set forth in Section 6.1.

2.20 "Federal Power Marketing Agency" means any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy.

2.21 "FERC" means the Federal Energy Regulatory Commission or any successor government agency.

2.22 "Force Majeure" means an event or circumstance which prevents one Party from performing its obligations under one or more Transactions, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (i) the loss of Buyer's markets; (ii) Buyer's inability economically to use or resell the Product purchased hereunder; (iii) the loss or failure of Seller's supply; or (iv) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred. The applicability of Force Majeure to the Transaction is governed by the terms of the Products and Related Definitions contained in Schedules P and Q.

2.23 "Gains" means, with respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of a Terminated Transaction, determined in a commercially reasonable manner.

2.24 "Governmental Charges" has the meaning set forth in Section 10.2

2.25 "Guarantor" means, with respect to a Party, the guarantor, if any, acceptable to the Party as set forth in the Supplementary Agreement attached hereto as Exhibit B.

2.26 "Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

2.27 "Imaged Document" has the meaning set forth in Section 11.17.

2.28 "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a credit rating of at least A- from S&P or A3 from Moody's, or a Canadian Bank if the applicant for such Letter of Credit has its principal place of business located in Canada, or such other entity as agreed to by the Parties, including but not limited to CoBank, ACB or National Rural Utilities Cooperative, in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

2.29 "Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of a Terminated Transaction, determined in a commercially reasonable manner.

2.30 "MEMA" means the Mid-Continent Energy Marketers Association, which is a Minnesota nonprofit corporation and independent energy marketing association.

2.31 "MEMA Member" means an entity approved for membership as a voting member (or any successor designation adopted by MEMA) in MEMA pursuant to article three of the MEMA bylaws and in compliance therewith, or any successor rules adopted by MEMA governing admission to membership.

2.32 "Moody's" means Moody's Investors Service, Inc. or its successor.

2.33 "NERC Business Day" means any day except a Saturday, Sunday or a holiday as defined by the North American Electric Reliability Corporation ("NERC") or any successor organization thereto. A NERC Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

2.34 "Non-Defaulting Party" has the meaning set forth in Section 6.2.

2.35 "Offsetting Transactions" mean any two or more outstanding Transactions, having the same or overlapping Delivery Period(s), Delivery Point and payment date, where under one or more of such Transactions, one Party is the Seller, and under the other such Transaction(s), the same Party is the Buyer.

2.36 "Option" means the right but not the obligation to purchase or sell a Product as specified in a Transaction.

2.37 "Option Buyer" means the Party specified in a Transaction as the purchaser of an option, as defined in Schedule P.

2.38 "Option Seller" means the Party specified in a Transaction as the seller of an option , as defined in Schedule P.

2.39 "Oral Confirmation" has the meaning set forth in Section 3.3.

2.40 "Party" means the Seller or the Buyer in a Transaction.

2.41 "Parties" means the Seller and the Buyer in a Transaction.

2.42 "Performance Assurance" means collateral in the form of either cash, Letter(s) of Credit, or other security acceptable to the Party requesting an assurance of performance.

2.43 "Potential Event of Default" means an event which, with notice or passage of time or both, would constitute an Event of Default.

2.44 "Product" means electric capacity, energy or other product(s) related thereto as specified in a Transaction by reference to a Product listed in Schedules P or Q hereto or as otherwise specified by the Parties in the Transaction.

2.45 "Put Option" means an Option entitling, but not obligating, the Option Buyer to sell and deliver the Product to the Option Seller at a price equal to the Strike Price for the Delivery Period for which the option may be exercised, all as specified in a Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller shall be obligated to purchase and receive the Product.

2.46 "Quantity" means that quantity of the Product that Seller agrees to make available or sell and deliver, or cause to be delivered, to Buyer, and that Buyer agrees to purchase and receive, or cause to be received, from Seller as specified in the Transaction.

2.47 "Replacement Price" means the price at which Buyer, acting in a commercially reasonable manner, purchases a replacement for any Product specified in a Transaction but not delivered by Seller, plus (i) costs reasonably incurred by Buyer in purchasing such substitute

Product and (ii) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or at Buyer's option, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller's liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party.

2.48 "S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

2.49 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells any Product not received by Buyer, deducting from such proceeds any (i) costs reasonably incurred by Seller in reselling such Product and (ii) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or at Seller's option, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer's liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party.

2.50 "Schedule" or "Scheduling" means the actions of Seller, Buyer and/or their designated representatives, including each Party's Transmission Providers, if applicable, of notifying, requesting and confirming to each other the quantity and type of Product to be delivered on any given day or days during the Delivery Period at a specified Delivery Point.

2.51 "Seller" means the MEMA Member to a Transaction that is obligated to sell and deliver, or cause to be delivered, the Product, as specified in the Transaction.

2.52 "Settlement Amount" means, with respect to a Transaction and the Non-Defaulting Party, the Losses or Gains, and Costs, expressed in U.S. Dollars, which such party incurs as a result of the liquidation of a Terminated Transaction pursuant to Section 6.2.

2.53 "Strike Price" means the price to be paid for the purchase of the Product pursuant to an Option.

2.54 "Tariff" means this Mid-Continent Energy Marketers Association Capacity and Energy Tariff.

2.55 "Terminated Transaction" has the meaning set forth in Section 6.2.

2.56 "Termination Payment" has the meaning set forth in Section 6.3.

2.57 "Transaction" means a particular transaction agreed to by the Parties relating to the sale and purchase of a Product pursuant to this Tariff.

2.58 "Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point in a particular Transaction.

2.59 "Website" means the Website maintained by MEMA at http://www.memarketers.org or successor site.

2.60 "Written Confirmation" has the meaning set forth in Section 3.2.

ARTICLE THREE: TRANSACTION TERMS AND CONDITIONS

3.1 Confirmations. A Transaction shall be entered into upon the agreement of the Parties by one or more of the following methods as evidenced in paragraph 1 of the Supplementary Agreement attached hereto as Exhibit B:

i) in writing in accordance with Section 3.2;

ii) orally in accordance with Section 3.3; or

iii) by electronic means of communication in accordance with Section 3.4

(a "Confirmation").

The Supplementary Agreement may contain additional terms relating to confirmation of a Transaction as may be agreed to by the Parties. If the Parties do not enter into a Supplementary Agreement or if no method for entering transactions is selected in a Supplementary Agreement between the Parties, then the Transactions shall be entered into orally. Each Party agrees not to contest, or assert any defense to, the validity or enforceability of the Transaction entered into in accordance with this Tariff (i) based on any law requiring agreements to be in writing or to be signed by the parties, or (ii) based on any lack of authority of the Party or any lack of authority o of any employee of the Party to enter into a Transaction.

3.2 Written Confirmation. When confirming a Transaction in writing, Seller shall forward to Buyer within three (3) Business Days after the Transaction is entered into a written confirmation substantially in the form of Exhibit A or other format as mutually agreed to by the Parties ("Written Confirmation"). When evidencing a Transaction by way of Oral Confirmation or Electronic Confirmation, Seller may also confirm the Transaction by forwarding to Buyer within three (3) Business Days after the Transaction is entered into, a Written Confirmation. If Buyer objects to any term(s) of such Written Confirmation, Buyer shall notify Seller in writing of such objections within two (2) Business Days of Buyer's receipt thereof, failing which Buyer shall be deemed to have accepted the terms as sent. If Seller fails to send a Written Confirmation within three (3) Business Days after the Transaction is entered into, a Written Confirmation substantially in the form of Exhibit A, may be forwarded by Buyer to Seller. If Seller objects to any term(s) of such Written Confirmation, Seller shall notify Buyer of such objections within two (2) Business Days of Seller's receipt thereof, failing which Seller shall be deemed to have accepted the terms as sent. If Seller and Buyer each send a Written Confirmation and neither Party objects to the other Party's Written Confirmation within two (2) Business Days of receipt, Seller's Written Confirmation shall be deemed to be accepted and shall be the controlling Confirmation, unless (i) Seller's Written Confirmation was sent more than three (3) Business Days after the Transaction was entered into and (ii) Buyer's Written Confirmation was sent prior to Seller's Written Confirmation, in which case Buyer's Written Confirmation shall be deemed to be accepted and shall be the controlling Confirmation. Failure by either Party to send or either Party to return an executed Written Confirmation or any objection by either Party shall not invalidate the Transaction agreed to by the Parties.

3.3 Oral Confirmation. When confirming a Transaction orally, each Party consents to the creation of a tape or electronic recording ("Oral Confirmation") of all telephone conversations between the Parties to a proposed Transaction under this Tariff, and that any such Oral Confirmation shall be retained in confidence, secured from improper access, and may be submitted in evidence in any proceeding or action relating to such proposed Transaction. Each Party waives any further notice of such monitoring or recording, and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees. The Oral Confirmation, and the terms and conditions described therein, if admissible, shall be the controlling evidence for the Parties' agreement with respect to a particular Transaction in the event a Written Confirmation or Electronic Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Written Confirmation or Electronic Confirmation, such Written Confirmation or Electronic Confirmation shall control in the event of any conflict with the terms of an Oral Confirmation, or in the event of any conflict with the terms of this Tariff.

3.4 Electronic Confirmation. When confirming a Transaction by an electronic means of communication for which a written record can be retrieved and which is mutually agreed upon by the Parties as evidenced in a Supplementary Agreement ("Electronic Confirmation"), the record of Electronic confirmation shall be retained in electronic form in confidence secured from improper access, and may, if properly authenticated, be submitted in evidence in any proceeding or action relating to such proposed Transaction. The Electronic Confirmation and the terms and conditions described therein, if admissible, shall be the controlling evidence of the Parties agreement with respect to a particular Transaction in the event a Written Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Written Confirmation, such Written Confirmation shall control in the event of any conflict with the terms of an Electronic Confirmation, or in the event of such conflict with the terms of this Tariff.

3.5 Governing Terms. Unless otherwise specifically agreed, each Transaction between the Parties shall be governed by this Tariff. This Tariff (including all exhibits, schedules and any written supplements hereto), any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmations accepted in accordance with Sections 3.2, 3.3 and 3.4) shall form a single integrated agreement between the Parties. Any inconsistency between any terms of this Tariff and any terms of the Transaction shall be resolved in favor of the terms of such Transaction.

3.6 Additional Confirmation Terms. The Parties to a Transaction may mutually agree to terms which modify or supplement the general terms and conditions of this Tariff either through, Written Confirmation or Supplementary Agreement.

ARTICLE FOUR: OBLIGATIONS AND DELIVERIES

4.1 Seller's and Buyer's Obligations. With respect to each Transaction, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Quantity of the Product at the Delivery Point, and Buyer shall pay Seller the Contract Price; provided, however, with respect to Options, the obligations set forth in the preceding sentence shall only arise if the Option Buyer exercises its Option in accordance with its terms. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product or its receipt at and from the Delivery Point.

4.2 Transmission and Scheduling. Seller shall arrange and be responsible for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

4.3 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify otherwise, the Claiming Party shall be excused from the performance of its obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

ARTICLE FIVE: REMEDIES FOR FAILURE TO DELIVER/RECEIVE

5.1 Seller Failure. If Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the Product or by Buyer's failure to perform, then Seller shall pay Buyer, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

5.2 Buyer Failure. If Buyer fails to schedule and/or receive all or part of the Product pursuant to a Transaction and such failure is not excused under the terms of the Product or by Seller's failure to perform, then Buyer shall pay Seller, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Sales Price from the Contract Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

ARTICLE SIX: EVENTS OF DEFAULT; REMEDIES

6.1 Events of Default. An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

a. the failure to make, when due, any payment required pursuant to a Transaction if such failure is not remedied within three (3) Business Days after written notice;
b. any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;
c. the failure to perform any material covenant or obligation set forth in a Transaction (except to the extent constituting a separate Event of Default, and except for such Party's obligations to deliver or receive the Product, the exclusive remedy for which is provided in Article Five) if such failure is not remedied within three (3) Business Days after written notice;
d. such Party becomes Bankrupt;
e. the failure of such Party to satisfy the creditworthiness/collateral requirements agreed to with the other Party;
f. such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under a Transaction to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party;
g. with respect to such Party's Guarantor, if any:

(i) if any representation or warranty made by a Guarantor in connection with a Transaction is false or misleading in any material respect when made or when deemed made or repeated;
(ii) the failure of a Guarantor to make any payment required or to perform any other material covenant or obligation in any guaranty made in connection with a Transaction and such failure shall not be remedied within three (3) Business Days after written notice;
(iii) a Guarantor becomes Bankrupt;
(iv) the failure of a Guarantor's guaranty to be in full force and effect for purposes of a Transaction (other than in accordance with its terms) prior to the satisfaction of all obligations of such Party under each Transaction to which such guaranty shall relate without the written consent of the other Party; or
(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of any guaranty.

6.2 Declaration of an Early Termination Date and Calculation of Settlement. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (the "Non-Defaulting Party") shall have the right (i) to designate a day, no earlier than the day such notice is effective and no later than 20 days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing between the Parties and to liquidate and terminate all, but not less than all, Transactions (each referred to as a "Terminated Transaction") between the Parties, (ii) withhold any payments due to the Defaulting Party under each Transaction and (iii) suspend performance. The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for each such Terminated Transaction as of the Early Termination Date (or, to the extent that in the reasonable opinion of the Non-Defaulting Party certain of such Terminated Transactions are commercially impracticable to liquidate and terminate or may not be liquidated and terminated under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable).

6.3 Net Out of Settlement Amounts. The Non-Defaulting Party shall aggregate all Settlement Amounts into a single amount by: netting out (a) all Settlement Amounts that are due to the Defaulting Party, plus, at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party pursuant to Article Nine, plus any or all other amounts due to the Defaulting Party under this Tariff against (b) all Settlement Amounts that are due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Tariff, so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one Party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

6.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Party that owes it within two (2) Business Days after such notice is effective.

6.5 Disputes With Respect to Termination Payment. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within two (2) Business Days of receipt of Non-Defaulting Party's calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall first transfer Performance Assurance to the Non-Defaulting Party in an amount equal to the Termination Payment.

6.6 Closeout Setoffs. After calculation of a Termination Payment in accordance with Section 6.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 6.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

6.7 Suspension of Performance. Notwithstanding any other provision of this Tariff, if (a) an Event of Default or (b) a Potential Event of Default shall have occurred and be continuing, the Non-Defaulting Party, upon written notice to the Defaulting Party, shall have the right (i) to suspend performance under any or all Transactions; provided, however, in no event shall any such suspension continue for longer than ten (10) NERC Business Days with respect to any single Transaction unless an Early Termination Date shall have been declared and notice thereof pursuant to Section 6.2 given, and (ii) to the extent an Event of Default shall have occurred and be continuing to exercise any remedy available at law or in equity.

ARTICLE SEVEN: PAYMENT AND NETTING

7.1 Billing Period. Unless otherwise specifically agreed upon by the Parties in a Transaction, the calendar month shall be the standard period for all payments under this Tariff (other than Termination Payments, payments pursuant to Section 5.1 or 5.2, and Option premium payments pursuant to Section 7.7). As soon as practicable after the end of each month, each Party shall render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

7.2 Timeliness of Payment. Unless otherwise agreed by the Parties in a Transaction, all invoices under this Tariff shall be due and payable in accordance with each Party's invoice instructions on or before the later of the twentieth (20th) day of each month, or tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. Each Party shall make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

7.3 Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Tariff or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 7.3 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which performance of a Transaction occurred, the right to payment for such performance is waived.

7.4 Netting of Payments. The Parties agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date pursuant to all Transactions through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Tariff, including any related damages calculated pursuant to Article Five, interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it. Notwithstanding the previous sentence, netting shall not apply to option premiums which shall be settled in accordance with Section 7.7.

7.5 Payment Obligation Absent Netting. If Parties agree not to do netting of payment pursuant to Section 7.4 or only one Party owes a debt or obligation to the other during the monthly billing period, including, but not limited to, any related damage amounts calculated pursuant to Article Five, interest, and payments or credits, that Party shall pay such sum in full when due.

7.6 Security. Unless the Party benefiting from Performance Assurance or a guaranty notifies the other Party in writing, and except in connection with a liquidation and termination in accordance with Article Six, all amounts netted pursuant to this Article Seven shall not take into account or include any Performance Assurance or guaranty which may be in effect to secure a Party's performance under this Tariff.

7.7 Payment for Options. The premium amount for the purchase of an Option shall be paid within two (2) Business Days of receipt of an invoice from the Option Seller. Upon exercise of an Option, payment for the Product underlying such Option shall be due in accordance with Section 7.1.

7.8 Transaction Netting. If the Parties enter into one or more Transactions, which in conjunction with one or more other outstanding Transactions, constitute Offsetting Transactions, then all such Offsetting Transactions may by agreement of the Parties, be netted into a single Transaction under which:

a. the Party obligated to deliver the greater amount of Energy shall deliver the difference between the total amount it is obligated to deliver and the total amount to be delivered to it under the Offsetting Transactions, and
b. the Party owing the greater aggregate payment shall pay the net difference owed between the Parties.

Each single Transaction resulting under this Section shall be deemed part of the single, indivisible contractual arrangement between the parties, and once such resulting Transaction occurs, outstanding obligations under the Offsetting Transactions which are satisfied by such offset shall terminate.

ARTICLE EIGHT: LIMITATIONS

EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS TARIFF SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED IN THIS TARIFF OR IN A TRANSACTION, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR

ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE NINE: CREDIT AND COLLATERAL REQUIREMENTS

9.1 The applicable credit and collateral requirements shall be as agreed to by the Parties to a Transaction as evidenced in the Supplementary Agreement attached hereto as Exhibit B. The Parties may elect to choose one of the following options as listed below. If the Parties do not enter into a Supplementary Agreement or if no option is selected in the Supplementary Agreement between the Parties, Option 1 shall apply exclusively.

9.2 Credit Assurances.

Option 1 - Standard Credit Assurance

If a Party has reasonable grounds to believe that the other Party's creditworthiness or performance under a Transaction has become unsatisfactory, such requesting Party will provide the other Party with written notice requesting Performance Assurance in an amount determined by the requesting Party in a commercially reasonable manner. Upon receipt of such notice the Party shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to the requesting Party. In the event that a Party receives a request for a Performance Assurance but fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to the requesting Party within three (3) Business Days of receipt of notice, then an Event of Default under Article Six will be deemed to have occurred and the Party requesting such Performance Assurance will be entitled to the remedies set forth in Article Six of this Tariff.

Option 2 - Enhanced Credit Assurance

Should a Party's creditworthiness or performance become unsatisfactory to the other Party in such other Party's reasonably exercised discretion with regard to any Transaction (including any Confirmation) pursuant to this Tariff, the dissatisfied Party (the "First Party") may require the other Party (the "Second Party") to provide Performance Assurance in an amount determined by the First Party in a commercially reasonable manner. Events which may trigger the First Party questioning the Second Party's creditworthiness or performance include, but are not limited to, the following:

(1) The First Party has knowledge that the Second Party (or its Guarantor, if applicable) is failing to perform or defaulting under other material contracts.
(2) The Second Party has exceeded any credit or trading limit set out in any Confirmation or other agreement between the Parties.
(3) The Second Party's (or its Guarantor's, if applicable) Credit Rating falls below BBB- from S&P or Baa3 from Moody's (based on the lower of the S&P or Moody's Credit Rating).

(4) Other material adverse changes in the Second Party's (or its Guarantor, if applicable) financial condition occur.
(5) Substantial changes in market prices which materially and adversely impact the Second Party's ability to perform under this Tariff or any Confirmation occur.

If the Second Party fails to provide Performance Assurance, or a guaranty or other credit assurance acceptable to the First Party within three (3) Business Days of receipt of notice, then an Event of Default under Article Six of the Tariff shall be deemed to have occurred and the First Party will be entitled to the remedies set forth in Article Six of this Tariff. Nothing contained in the Article Nine shall affect any credit agreement or arrangement, if any, between the Parties.

Option 3 - Downgrade Event

If at any time there shall occur a Downgrade Event with respect to either Party, then the non-affected Party (the "First Party") may require the affected Party (the "Second Party") to provide Performance Assurance in an amount determined by the First Party in a commercially reasonable manner. In the event the Second Party shall fail to provide such Performance Assurance or guaranty or other credit assurance acceptable to the First Party within three (3) Business Days of receipt of notice, than an Event of Default shall be deemed to have occurred and the First Party will be entitled to exercise any of the remedies set forth in Article Six of the Tariff.

The Parties shall specify within a Supplementary Agreement the meaning of a Downgrade Event with respect to each Party.

Option 4 - Mutually Agreed to Credit Assurance

As mutually agreed in writing by both Parties and referenced in the Supplementary Agreement.

9.3 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent either or both Parties deliver Performance Assurance hereunder, unless prohibited by applicable law, each Party (a "Pledgor") hereby grants to the other Party (the "Secured Party") a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order to perfect the Secured Party's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, the Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a secured party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in the possession of the Non-Defaulting Party or its agent; (iii) draw on any outstanding Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

ARTICLE TEN: GOVERNMENTAL CHARGES

10.1 Cooperation. Each Party to a Transaction shall use reasonable efforts to implement the provisions of and to administer this Tariff in accordance with the intent of the Parties to minimize all taxes, so long as neither Party is materially adversely affected by such efforts.

10.2 Governmental Charges. Seller shall pay or cause to be paid all taxes imposed by any government authority ("Governmental Charges") on or with respect to the Product or a Transaction arising prior to the Delivery Point. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or a Transaction at and from the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Product and are, therefore, the responsibility of the Seller). In the event Seller is required by law or regulation to remit or pay Governmental Charges which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Governmental Charges. If Buyer is required by law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, Buyer may deduct the amount of any such Governmental Charges from the sums due to Seller under Article Seven of this Agreement. Nothing shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the law.

ARTICLE ELEVEN: MISCELLANEOUS

11.1 Term of Tariff. This Tariff shall be effective as of the effective date accepted by the FERC. This Tariff shall remain in effect until terminated by MEMA or successor organization upon sixty (60) days prior written notice; provided, however, no such termination notice shall be effective as to any ongoing Transaction hereunder until the Parties have fulfilled all Tariff obligations with respect to Transactions agreed to prior to the date of termination and until regulatory approval, if required, is granted to terminate this Tariff.

11.2 Representations and Warranties. On the date of entering into each Transaction, each Party represents and warrants to the other Party that:

(i) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(ii) it has all regulatory authorizations necessary for it to legally perform its obligations under this Tariff and each Transaction (including any Confirmation accepted in accordance with Article Three);

(iii) the execution, delivery and performance of this Tariff and each Transaction (including any Confirmation accepted in accordance with Article Three) are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(iv) this Tariff, each Transaction (including any Confirmation), and each other document executed and delivered in accordance with this Tariff (including but not limited to the Supplementary Agreement) constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses.

(v) it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

(vi) there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Tariff and each Transaction (including any Confirmation);

(vii) no Event of Default or Potential Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Tariff and each Transaction (including any Confirmation);

(viii) it is acting for its own account, has made its own independent decision to enter into each Transaction (including any Confirmation) and as to whether this Tariff and each such Transaction (including any Confirmation) is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of another Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Tariff and each Transaction (including any Confirmation);

(ix) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code;

(x) it has entered into each Transaction (including any Confirmation) in connection with the conduct of its business and it has the capacity or ability to make or take delivery of all Products referred to in the Transaction to which it is a Party;

(xi) with respect to each Transaction (including any Confirmation) involving the purchase or sale of a Product or an Option, it is a producer, processor, commercial user or merchant handling the Product, and it is entering into such Transaction for purposes related to its business as such; and

(xii) the material economic terms of each Transaction are subject to individual negotiation by the Parties.

11.3 Title and Risk of Loss. Title to and risk of loss related to the Product shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it shall deliver to Buyer the Quantity of the Product free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

11.4 Indemnity. Each Party shall indemnify, defend and hold harmless the other Party from and against any Claims arising from or out of any event, circumstance, act or incident first occurring or existing during the period when control and title to Product is vested in such Party as provided in Section 11.3. Each Party shall indemnify, defend and hold harmless the other Party against any Governmental Charges for which such Party is responsible under Article Ten.

11.5 Assignment. No Party shall assign a Transaction or any of its rights under a Transaction without the prior written consent of the other Party, which consent may not unreasonably be withheld; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign a Transaction or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign a Transaction to an Affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (iii) transfer or assign a Transaction to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

11.6 Governing Law. THIS TARIFF AND THE RIGHTS AND DUTIES OF PARTIES TO A TRANSACTION, TO THE EXTENT PERMITTED BY LAW, SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITH THE EXCEPTION OF UNITED STATES FEDERAL LAW OR CANADIAN LAWS WITH RESPECT TO THE SALE OF ELECTRICAL CAPACITY OR ENERGY IN CANADA. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS TARIFF.

11.7 Notices. All notices, requests, statements or payments shall be made as specified in the Supplementary Agreement or if the Parties do not enter into a Supplementary Agreement then as specified in a Transaction (including any Confirmation).. Notices (other than scheduling requests) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight mail or courier shall be effective on the next Business Day after it was sent. A Party may change its addresses by providing notice of same in accordance herewith. Notwithstanding the foregoing, a Party is entitled to rely on the other Party's invoice regarding payment instructions.

11.8 General. This Tariff (including the exhibits, schedules, the Supplementary Agreement and any written supplements hereto), any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmation) constitute the entire agreement between the Parties relating to the subject matter. Notwithstanding the foregoing, any collateral, credit support or margin agreement or similar arrangement between the Parties shall, upon designation by the Parties, be deemed part of a Transaction and shall be incorporated therein by reference. Each Party to a Transaction agrees if it seeks to amend any applicable wholesale power sales tariff during the term of a Transaction, such amendment shall not in any way affect such Transaction under this Tariff without the prior written consent of the other Party. Each Party to a Transaction further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Tariff. Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as "Regulatory Event") shall not otherwise affect the remaining lawful obligations that arise under this Tariff; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform their Transaction in order to give effect to the original intention of the Parties. The term "including" when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only. All indemnity and audit rights shall survive the termination of the applicable Transaction for twelve (12) months.

11.9 Audit. Each Party has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Tariff. If requested, a Party shall provide to the other Party statements evidencing the Quantity delivered at the Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof shall be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment shall be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

11.10 Forward Contract. The Parties acknowledge and agree that all Transactions constitute "forward contracts" within the meaning of the United States Bankruptcy Code.

11.11 Confidentiality. The Parties agree that neither Party shall disclose the terms or conditions of the Transaction(s) to a third party (other than the Party's or its Affiliate's employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area, regional reliability council, or independent system operator rule, or in connection with any court or regulatory proceeding; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation.

11.12 Resolution of Disputes. Prior to the initiation of arbitration, any controversy, dispute or claim between the Parties involving or arising under this Tariff first shall be referred for resolution to a senior representative of each Party. A Party claiming that a dispute has arisen must give written notice within a reasonable period of time to the other Party describing the dispute and designating the Party's senior representative. Upon receipt of a notice describing the dispute, the other Party shall promptly designate its senior representative to the notifying Party. The senior representatives so designated shall attempt to resolve the dispute on an informal basis as promptly as practicable. If the dispute has not been resolved within thirty (30) days after the notifying Party's notice was received by the other Party, or within such other period as the Parties may jointly agree, the Parties shall submit the dispute to arbitration in accordance with the arbitration procedure set forth in Section 11.13.

11.13 Arbitration. Any controversy, dispute or claim involving or arising under this Tariff which cannot be resolved pursuant to Section 11.12 shall be submitted to binding arbitration by one arbitrator qualified by education, experience or training to render a decision upon the issues in dispute and who has not previously been employed by either Party, and does not have a direct or indirect interest in either Party or the subject matter of the arbitration. Such arbitrator shall either be mutually agreed upon by the Parties within thirty (30) days after written notice from either Party requesting arbitration, or failing agreement, the arbitration shall be conducted by a panel of three arbitrators having the qualifications set forth in the preceding sentence, one to be selected by each Party and the third arbitrator to be selected by the two arbitrators selected by the Parties. If either Party fails to notify the other Party of the arbitrator selected by it within ten (10) days after receiving notice of the other Party's arbitrator, or if the two arbitrators selected fail to select a third arbitrator within ten (10) days after notice is given of the selection of the second arbitrator, then such arbitrator shall be selected under the expedited rules of the American Arbitration Association (the "AAA"). The Parties shall divide equally the cost of the hearing, and each Party shall be responsible for its own expenses and those of its counsel or other representative. The commercial arbitration rules of the AAA shall apply to the extent not inconsistent with the rules specified above. Unless otherwise agreed to by the Parties, all arbitrations shall be held in St. Paul, Minnesota.

11.14 Laws of the United States. This Tariff shall not make any laws or regulations governing employment or production of goods and services enacted by the Congress of the United States or by any other legislative or governmental body in the United States or any state thereof applicable to any power or other service provided or used in Canada. This Tariff shall not confer or extend the authority or jurisdiction of FERC or any regulatory agency over matters pertaining to the generation, sale, purchase or transmission of electric energy in Canada.

11.15 Compliance with Applicable Laws. This Tariff shall be binding on all Parties to the maximum extent permitted by United States federal and state law or regulation, and Canadian federal and/or provincial government law or regulation, but notwithstanding any other provision of this Tariff, no Party shall be required to take any action or do any other thing with respect to rates, charges, terms or conditions of service, the resolution of disputes under this Tariff, or any other matter, that (a) it is not permitted by law to undertake or that is prohibited in whole or in part by any law or regulation applicable to such a Party, or (b) would require such a

Party to violate a provision of such law or regulation in order to comply with this Tariff. Each Party shall seek such approvals, grant such waivers, and take such other actions as may be necessary to comply with this Tariff, to the maximum extent permitted by United States federal or state law or regulation, or Canadian federal or provincial law or regulation.

11.16 Effect of Canadian Laws. The sale, purchase and transmission of electricity in Canada and the rates, charges, terms and conditions of service therefore are subject in all respects to Canadian Laws. This includes but is not limited to:

(i) The final authority of the Government of Canada in all matters relating to the export of electric power; and
(ii) The final authority of the government of a Canadian province in all matters relating to the installation or construction of facilities.

11.17 Imaged Documents. Any original executed document relating to this Agreement may be scanned and stored on computer tapes and disks (the "Imaged Document"). The Imaged Document if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the Imaged Document on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

SCHEDULE M

(THIS SCHEDULE IS INCLUDED IF A PARTY IS A FEDERAL POWER MARKETING AGENCY)

A. If either Party is a Federal Power Marketing Agency, the Parties agree that the following provisions apply to this Tariff and any Transaction conducted under this Tariff:

1. Participation by the United States. The participation by the United States through a Federal Power Marketing Agency in this Tariff is subject in all respects to acts of Congress and to regulations of the Secretary of Energy established thereunder, and to rate schedules promulgated by the Secretary of Energy or delegate. This reservation includes, but is not limited to, the statutory limitations upon the authority of the Secretary of Energy to submit disputes arising under this Tariff to arbitration. In the event of a conflict between this Schedule M and any other provision in this Tariff, this Schedule M shall have precedence with respect to the application of this Tariff to the United States.

2. Contingent Upon Appropriations. Where activities provided for in this Tariff extend beyond the current fiscal year of a Federal Power Marketing Agency, continued expenditures by the United States are contingent upon Congress making the necessary appropriations required for the continued performance of the obligations of the United States under this Tariff. In case such appropriation is not made, a Party to a Transaction with a Federal Power Marketing Agency hereby releases the United States from its contractual obligations under this Tariff and from all liability due to the failure of Congress to make such appropriation.

3. Officials Not To Benefit. No member of or delegate to Congress or Resident Commissioner shall be admitted to any share or part of this Tariff or to any benefit that may have arisen from this Tariff, but this restriction shall not be construed to extend to this Tariff if made with a corporation or company for its general benefit.

4. Covenant Against Contingent Fees. A Party to a Transaction with a Federal Power Marketing Agency warrants that no person or selling agency has been employed or retained to solicit or secure participation by a Federal Power Marketing Agency in this Tariff upon an agreement or understanding for a commission, percentage, brokerage or contingent fee, excepting bona fide employees or bona fide established commercial or selling agencies maintained by the Party for the purpose of securing business. For breach or violation of this warranty, the Party that is a Federal Power Marketing Agency shall have the right to annul its participation in this Tariff without liability or, in its

discretion, to deduct from the contract price or consideration the full amount of such commission, percentage, brokerage, or contingent fee.

5. Contractor Agreement. For the purpose of this Schedule M the term "Tariff" shall mean this Tariff and the term "Contractor" shall mean a Party having a Transaction with a Federal Power Marketing Agency. During the performance of a Transaction under this Tariff, the Contractor agrees to the following provisions. In addition, the Contractor shall include the following provisions in every subcontract or purchase order involving the Federal Power Marketing Agency unless exempted by rules, regulations or order of the Secretary of Labor.

6. Equal Opportunity Employment Practices. Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), which provides, among other things, that the Contractor shall not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Tariff.

7. Contract Work Hours and Safety Standards. The Tariff, to the extent that it is of a character specified in Section 103 of the Contract Work Hours and Safety Standards Act, 40 U.S.C. § 329 (1986) (the "Act"), is subject to the provisions of the Act, 40 U.S.C. §§ 327-333 (1986), and to regulations promulgated by the Secretary of Labor pursuant to the Act.

8. Use of Convict Labor. The Contractor agrees not to employ any person undergoing sentence of imprisonment in performing the Tariff except as provided by 18 U.S.C. § 4082(c)(2) (1986) and Executive Order 11755, 39 Fed. Reg. 779 (1973).

SCHEDULE P: PRODUCTS AND RELATED DEFINITIONS

"Ancillary Services" means any of the services identified by a Transmission Provider in its transmission tariff as "ancillary services" including, but not limited to, regulation and frequency response, energy imbalance, operating reserve-spinning and operating reserve-supplemental, as may be specified in the Transaction.

"Capacity" has the meaning specified in the Transaction.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in megawatt hours.

"Environmental Attributes" means an aspect, claim, characteristic or benefit associated with the generation of a quantity of Energy by an electricity generation facility that is capable of being measured, verified or calculated, including any and all credits, benefits, emissions reductions, offsets and allowances, howsoever entitled, attributable to the generation of such quantity of Energy by an electricity generation facility and its displacement of conventional, non-renewable electricity generation together with the right(s) to report ownership of such attributes to any agency, authority, or third party. Environmental Attributes shall not include (i) any Energy, Capacity, reliability or other power attributes from the electricity generation facility; (ii) production tax credits associated with the construction or operation of the electricity generation facility and other financial incentives in the form of credits, reductions or allowances associated with the electricity generation facility that are applicable to a state, provincial or federal income taxation obligation; (iii) fuel-related subsidies, "tipping fees", or other local subsidies received by the electricity generation facility for the destruction of particular preexisting pollutants or the promotion of local environmental benefits; or (iv) emission reduction credits encumbered or used by the electricity generation facility for compliance with local, state, provincial or federal operating and/or air quality permits.

"Firm (LD)" means, with respect to a Transaction, that either Party shall be relieved of its obligations to sell and deliver or purchase and receive without liability only to the extent that, and for the period during which, such performance is prevented by Force Majeure. In the absence of Force Majeure, the Party to which performance is owed shall be entitled to receive from the Party which failed to deliver/receive an amount determined pursuant to Article Five.

"Firm Transmission Contingent - Contract Path" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Five, if the transmission for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the Transmission Provider(s) for the Product in the case of the Seller from the generation source to the Delivery Point or in the case of the Buyer from the Delivery Point to the ultimate sink, and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable Transmission Provider's tariff. This contingency shall excuse performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Section 2.22 to the contrary.

"Firm Transmission Contingent - Delivery Point" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Five, if the transmission to the Delivery Point (in the case of Seller) or from the Delivery Point (in the case of Buyer) for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the Transmission Provider(s) for the Product, in the case of the Seller, to be delivered to the Delivery Point or, in the case of Buyer, to be received at the Delivery Point and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable Transmission Provider's tariff. This transmission contingency excuses performance for the duration of the interruption or curtailment, notwithstanding the provisions of the definition of "Force Majeure" in Section 2.22 to the contrary. Interruptions or curtailments of transmission other than the transmission either immediately to or from the Delivery Point shall not excuse performance

"Firm (No Force Majeure)" means, with respect to a Transaction, that if either Party fails to perform its obligation to sell and deliver or purchase and receive the Product, the Party to which performance is owed shall be entitled to receive from the Party which failed to perform an amount determined pursuant to Article Five. Force Majeure shall not excuse performance of a Firm (No Force Majeure) Transaction.

"Into ______________ (the "Receiving Transmission Provider"), Seller's Daily Choice" means that, in accordance with the provisions set forth below, (1) the Product shall be scheduled and delivered to an interconnection or interface ("Interface") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which Interface, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area; and (2) Seller has the right on a daily prescheduled basis to designate the Interface where the Product shall be delivered. An "Into" Product shall be subject to the following provisions:

1. Prescheduling and Notification. Subject to the provisions of Section 6 of this Schedule, not later than the prescheduling deadline of 11:00 a.m. CPT on the Business Day before the next delivery day or as otherwise agreed to by Buyer and Seller, Seller shall notify Buyer ("Seller's Notification") of Seller's immediate upstream counterparty and the Interface (the "Designated Interface") where Seller shall deliver the Product for the next delivery day, and Buyer shall notify Seller of Buyer's immediate downstream counterparty.

2. Availability of "Firm Transmission" to Buyer at Designated Interface; "Timely Request for Transmission," "ADI" and "Available Transmission." In determining availability to Buyer of next-day firm transmission ("Firm Transmission") from the Designated Interface, a "Timely Request for Transmission" shall mean a properly

completed request for Firm Transmission made by Buyer in accordance with the controlling tariff procedures, which request shall be submitted to the Receiving Transmission Provider no later than 30 minutes after delivery of Seller's Notification, provided, however, if the Receiving Transmission Provider is not accepting requests for Firm Transmission at the time of Seller's Notification, then such request by Buyer shall be made within 30 minutes of the time when the Receiving Transmission Provider first opens thereafter for purposes of accepting requests for Firm Transmission.

Pursuant to the terms hereof, delivery of the Product may under certain circumstances be redesignated to occur at an Interface other than the Designated Interface (any such alternate designated interface, an "ADI") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which ADI, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area using either firm or non-firm transmission, as available on a day-ahead or hourly basis (individually or collectively referred to as "Available Transmission") within the Receiving Transmission Provider's transmission system.

3. Rights of Buyer and Seller Depending Upon Availability of Timely Request for Firm Transmission.

   A. Timely Request for Firm Transmission made by Buyer, Accepted by the Receiving Transmission Provider and Purchased by Buyer. If a Timely Request for Firm Transmission is made by Buyer and is accepted by the Receiving Transmission Provider and Buyer purchases such Firm Transmission, then Seller shall deliver and Buyer shall receive the Product at the Designated Interface.

      i If the Firm Transmission purchased by Buyer within the Receiving Transmission Provider's transmission system from the Designated Interface ceases to be available to Buyer for any reason, or if Seller is unable to deliver the Product at the Designated Interface for any reason except Buyer's non-performance, then at Seller's choice from among the following, Seller shall: (a) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, require Buyer to purchase such Firm Transmission from such ADI, and schedule and deliver the affected portion of the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, or (b) require Buyer to purchase non-firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by Seller, or (c) to the extent firm transmission is available on an hourly basis, require Buyer to purchase firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of such hourly firm transmission from the Designated Interface or an ADI designated by Seller.

ii If the Available Transmission utilized by Buyer as required by Seller pursuant to Section 3A(i) ceases to be available to Buyer for any reason, then Seller shall again have those alternatives stated in Section 3A(i) in order to satisfy its obligations.

iii Seller's obligation to schedule and deliver the Product at an ADI is subject to Buyer's obligation referenced in Section 4B to cooperate reasonably therewith. If Buyer and Seller cannot complete the scheduling and/or delivery at an ADI, then Buyer shall be deemed to have satisfied its receipt obligations to Seller and Seller shall be deemed to have failed its delivery obligations to Buyer, and Seller shall be liable to Buyer for amounts determined pursuant to Article Five.

iv In each instance in which Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI pursuant to Sections 3A(i) or (ii), and Firm Transmission had been purchased by both Seller and Buyer into and within the Receiving Transmission Provider's transmission system as to the scheduled delivery which could not be completed as a result of the interruption or curtailment of such Firm Transmission, Buyer and Seller shall bear their respective transmission expenses and/or associated congestion charges incurred in connection with efforts to complete delivery by such alternative scheduling and delivery arrangements. In any instance except as set forth in the immediately preceding sentence, Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI under Sections 3A(i) or (ii), Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with such alternative scheduling arrangements.

B. Timely Request for Firm Transmission Made by Buyer but Rejected by the Receiving Transmission Provider. If Buyer's Timely Request for Firm Transmission is rejected by the Receiving Transmission Provider because of unavailability of Firm Transmission from the Designated Interface, then Buyer shall notify Seller within 15 minutes after receipt of the Receiving Transmission Provider's notice of rejection ("Buyer's Rejection Notice"). If Buyer timely notifies Seller of such unavailability of Firm Transmission from the Designated Interface, then Seller shall be obligated either (1) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, to require Buyer to purchase (at Buyer's own expense) such Firm Transmission from such ADI and schedule and deliver the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, and thereafter the provisions in Section 3A shall apply, or (2) to require Buyer to purchase (at Buyer's own expense) non-firm transmission, and schedule and deliver the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by the Seller, in which case Seller shall bear the risk of interruption or curtailment of the non-firm transmission; provided, however, that if the non-firm transmission is interrupted or curtailed or if Seller is unable to deliver the Product for any reason, Seller shall have the right to schedule and deliver the Product to another ADI in order to satisfy its delivery obligations, in which case Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with Seller's inability to deliver the Product as originally prescheduled. If Buyer fails to timely notify Seller of the unavailability of Firm Transmission, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface, and the provisions of Section 3D shall apply.

C. Timely Request for Firm Transmission Made by Buyer, Accepted by the Receiving Transmission Provider and not Purchased by Buyer. If Buyer's Timely Request for Firm Transmission is accepted by the Receiving Transmission Provider but Buyer elects to purchase non-firm transmission rather than Firm Transmission to take delivery of the Product, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Five.

D. No Timely Request for Firm Transmission Made by Buyer, or Buyer Fails to Timely Send Buyer's Rejection Notice. If Buyer fails to make a Timely Request for Firm Transmission or Buyer fails to timely deliver Buyer's Rejection Notice, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Five.

4. Transmission.

A. Seller's Responsibilities. Seller shall be responsible for transmission required to deliver the Product to the Designated Interface or ADI, as the case may be. It is expressly agreed that Seller is not required to utilize Firm Transmission for its delivery obligations hereunder, and Seller shall bear the risk of utilizing non-firm transmission. If Seller's scheduled delivery to Buyer is interrupted as a result of Buyer's attempted transmission of the Product beyond the Receiving Transmission Provider's system border, then Seller will be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for damages pursuant to Article Five.

B. Buyer's Responsibilities. Buyer shall be responsible for transmission required to receive and transmit the Product at and from the Designated Interface or ADI, as the case may be, and except as specifically provided in Section 3A and 3B, shall be responsible for any costs associated with transmission therefrom. If Seller is attempting to complete the designation of an ADI as a result of Seller's rights and obligations hereunder, Buyer shall co-operate reasonably with Seller in order to effect such alternate designation.

5. Force Majeure. An "Into" Product shall be subject to the "Force Majeure" provisions in Section 2.22.

6. Multiple Parties in Delivery Chain Involving a Designated Interface. Seller and Buyer recognize that there may be multiple parties involved in the delivery and receipt of the Product at the Designated Interface or ADI to the extent that (1) Seller may be purchasing the Product from a succession of other sellers ("Other Sellers"), the first of which Other Sellers shall be causing the Product to be generated from a source ("Source Seller") and/or (2) Buyer may be selling the Product to a succession of other buyers ("Other Buyers"), the last of which Other Buyers shall be using the Product to serve its energy needs ("Sink Buyer"). Seller and Buyer further recognize that in certain Transactions neither Seller nor Buyer may originate the decision as to either (a) the original identification of the Designated Interface or ADI (which designation may be made by the Source Seller) or (b) the Timely Request for Firm Transmission or the purchase of other Available Transmission (which request may be made by the Sink Buyer). Accordingly, Seller and Buyer agree as follows:

A. If Seller is not the Source Seller, then Seller shall notify Buyer of the Designated Interface promptly after Seller is notified thereof by the Other Seller with whom Seller has a contractual relationship, but in no event may such designation of the Designated Interface be later than the prescheduling deadline pertaining to the Transaction between Buyer and Seller pursuant to Section 1 of this Schedule.

B. If Buyer is not the Sink Buyer, then Buyer shall notify the Other Buyer with whom Buyer has a contractual relationship of the Designated Interface promptly after Seller notifies Buyer thereof, with the intent being that the party bearing actual responsibility to secure transmission shall have up to 30 minutes after receipt of the Designated Interface to submit its Timely Request for Firm Transmission.

C. Seller and Buyer each agree that any other communications or actions required to be given or made in connection with this "Into Product" (including without limitation, information relating to an ADI) shall be made or taken promptly after receipt of the relevant information from the Other Sellers and Other Buyers, as the case may be.

D. Seller and Buyer each agree that in certain Transactions time is of the essence and it may be desirable to provide necessary information to Other Sellers and Other Buyers in order to complete the scheduling and delivery of the Product. Accordingly, Seller and Buyer agree that each has the right, but not the obligation, to provide information at its own risk to Other Sellers and Other Buyers, as the case may be, in order to effect the prescheduling, scheduling and delivery of the Product.

"Non-Firm" means, with respect to a Transaction, that delivery or receipt of the Product may be interrupted for any reason or for no reason, without liability on the part of either Party.

"Renewable Energy Credit" or "REC" has the meaning specified in the Transaction.

"System Firm" means that the Product will be supplied from the owned or controlled generation or pre-existing purchased power assets of the system specified in the Transaction (the "System") with non-firm transmission to and from the Delivery Point, unless a different Transmission Contingency is specified in a Transaction. Seller's failure to deliver shall be excused: (i) by an event or circumstance which prevents Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Seller; (ii) by Buyer's failure to perform; (iii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on, the System; (iv) to the extent the System or the control area or reliability council within which the System operates declares an emergency condition, as determined in the system's, or the control area's, or reliability council's reasonable judgment; or (v) by the interruption or curtailment of transmission to the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Seller's performance. Buyer's failure to receive shall be excused (i) by Force Majeure; (ii) by Seller's failure to perform, or (iii) by the interruption or curtailment of transmission from the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Buyer's performance. In any of such events, neither Party shall be liable to the other for any damages, including any amounts determined pursuant to Article Five.

"Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Five, if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm. If the transmission (whether firm or non-firm) that Seller or Buyer is attempting to secure is from source to sink is unavailable, this contingency excuses performance for the entire Transaction. If the transmission (whether firm or non-firm) that Seller or Buyer has secured from source to sink is interrupted or curtailed for any reason, this contingency excuses performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Article 2.22 to the contrary.

"Unit Firm" means, with respect to a Transaction, that the Product subject to the Transaction is intended to be supplied from a generation asset or assets specified in the Transaction. Seller's failure to deliver under a "Unit Firm" Transaction shall be excused: (i) if the specified generation asset(s) are unavailable as a result of a Forced Outage (as defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines) or (ii) by an event or circumstance that affects the specified generation asset(s) so as to prevent Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, and which is not within the reasonable control of, or the result of the negligence of, the Seller or (iii) by Buyer's failure to perform. In any of such events, Seller shall not be liable to Buyer for any damages, including any amounts determined pursuant to Article Five.

SCHEDULE Q: MAPP GRSP AND OTHER MAPP PRODUCTS

GENERAL TERMS AND CONDITIONS

1. **General**

1.1 The Products described herein are intended to facilitate the exchange of capacity and energy in the Mid-Continent Area Power Pool ("MAPP"). The Products employ market based rates for interchange of capacity and energy.

1.2 Governance. Capitalized terms used, but not defined, in Schedule Q of this Tariff shall have the meaning ascribed to them in the MAPP Restated Agreement. In the event of a conflict between the terms of this Tariff and the terms of the MAPP Restated Agreement, the terms of this Tariff shall control.

2. **Accreditation**

2.1 Accreditation of capacity transactions shall be determined and assigned under applicable procedures of the MAPP Generation Reserve Sharing Pool ("GRSP").

3. **Transmission Loading Relief**

3.1 Delivery of energy shall be subject to the applicable transmission provider's loading relief procedures.

4. **Definitions**

4.1 Public Utility: A public utility as defined in Section 201(e) of the Federal Power Act, as amended.[1]

4.2 MAPP means Mid-Continent Area Power Pool, which is an association of electric utilities and other electric industry participants organized for the purpose of pooling generation and transmission.

4.3 GRSP means the MAPP Generation Reserve Sharing Pool or its successor, as defined in the MAPP Restated Agreement.

5. **Uncontrollable Forces**

5.1 Force Majeure (Section 2.22), as defined and used in this Tariff, does not apply to any of the Products in this Schedule Q.

5.2 All Products in this Schedule Q are subject to "uncontrollable forces" or "force majeure". A Party shall not be considered to be in default in respect to any obligation under a Product in this Schedule Q if prevented from fulfilling such obligation by reason of "uncontrollable forces" or "force majeure", except that the

1 Note that the Energy Policy Act 2005 exempted a variety of entities, including electric cooperatives that sell less than 4 million MWh of energy per year from FERC jurisdiction over the determination of their ability to sell at negotiated rates.

obligation to pay money in a timely manner is absolute and shall not be subject to "uncontrollable forces" or "force majeure". Any Party unable to fulfill any obligation by reason of "uncontrollable forces" or "force majeure" will exercise due diligence to remove such disability with reasonable dispatch, but such obligation shall not require the settlement of a labor dispute except in the sole discretion of the Party experiencing such labor dispute. For the purposes of this Section 5.2 "uncontrollable forces" and/or "force majeure" shall have the meaning ascribed to such terms in the Transmission Provider's tariff.

Product A: Participation Power Interchange Service

1. Service to be Provided

1.1 This Product provides for the sale of Participation Power by a Seller to a Buyer from a specific generating unit or units. Participation Power shall mean power and energy sold from a specific generating unit or units on a continuously available basis except when such unit or units are temporarily out of service for maintenance, during which time the delivery of energy from other sources shall be at the Seller's option.

2. Conditions of Service

2.1 This Product shall be available for a period of one or more consecutive days.

2.2 Participation Power shall be supplied through transmission facilities that have adequate capacity for transmitting such power and energy, in accordance with any applicable reliability standards and procedures.

3. Schedules of Rates

3.1 The rates and term for Participation Power shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the Federal Energy Regulatory Commission ("FERC"), or (ii) is not a Public Utility.

3.2 In the event the service cannot be supplied on the effective date of an agreement to sell Participation Power because of a delayed in-service date of the associated generating facility or facilities, the capacity payment to be paid by the Buyer shall not be effective until the date such facility or facilities are placed in commercial operation.

Product J: Firm Power Interchange Service

1. **Service to be Provided**

   1.1 This Product provides for the sale of Firm Power by a Seller to a Buyer.

2. **Conditions of Service**

   2.1 Firm Power shall be supplied through transmission facilities which have adequate capacity for transmitting such power and energy, in accordance with any applicable GRSP reliability standards and procedures.

   2.2 This Product shall be available for a period of one or more consecutive days.

   2.3 Energy available under this Product may be supplied in one of the following forms:

   i. Energy is available at all times during the period covered by the commitment; or

   ii. If energy is being supplied as peaking energy, or for other purposes which anticipate a capacity-factor limitation, the Seller and the Buyer may mutually agree on minimum or maximum limits on the energy to be delivered during the period covered by the Transaction; provided, however, service under this paragraph 2.3(ii) shall not be interruptible for reasons other than reliability of service to native load.

3. **Schedule of Rates**

   3.1 The rates and term for Firm Power shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the FERC, or (ii) is not a Public Utility.

Product K: System Participation Power Interchange Service

1. Service to be Provided

1.1 This Product provides for the sale of System Participation Power by a Seller to a Buyer for a specified period for the purpose of obtaining a supply of power that can be depended upon with the same degree of assurance as that expected from the Buyer's own generating capacity, but which does not include reserve capacity.

2. Conditions of Service

2.1 This Product shall be available for periods of one or more consecutive days.

2.2 System Participation Power is intended to be available at all times during the period covered by the Transaction; provided, however, that if conditions arise during the period covered by the Transaction that would otherwise require curtailment of service to its native load customers, the Seller has the right to notify and require the Buyer to reduce its take of such energy to any amount specified and for any portion of the term of the Transaction; provided, however, this paragraph 2.2 shall not be used to allow interruptions for reasons other than reliability of service to native load. The Buyer shall promptly comply with such requirements of the Seller.

2.3 System Participation Power shall be supplied through transmission facilities that have adequate capacity for transmitting such power and energy, in accordance with any applicable GRSP reliability standards and procedures.

3. Schedule of Rates

3.1 The rates and term for System Participation Power shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the FERC, or (ii) is not a Public Utility.

Product L: Interruptible Load Replacement Energy Service

1. Service to be Provided

1.1 This Product provides for the supply of Interruptible Load Replacement Energy by a Seller to a Buyer when it is economical and practical to do so under the conditions set forth hereinafter.

2. Conditions of Service

2.1 Interruptible Load Replacement Energy may be used by a Buyer to serve interruptible load when that load would otherwise be interrupted.

2.1.1 In order to be eligible for Interruptible Load Replacement Energy Service, the Buyer must report in advance monthly quantities of Certified Interruptible Demand, as specified by the GRSP.

2.1.2 The rate of delivery of energy supplied under this Product in any hour shall not exceed the Buyer's total Certified Interruptible Demand ("CID").

2.1.3 Deliveries of energy may be received under this Product only when a Buyer's maximum System Demand would otherwise be greater than such Buyer's forecast System Demand for the current season, and shall not exceed the lesser of either that required to reduce the expected System Demand to the forecast System Demand or the Buyer's Certified Interruptible Demand being served by a purchase under this Product L.

2.1.4 Interruptible Load Replacement Energy Service shall be supplied through transmission facilities which have adequate capacity for transmitting such power and energy, in accordance with any applicable GRSP reliability standards and procedures.

3. Schedules of Rates

3.1 The rates and term for Interruptible Load Replacement Energy Service shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the FERC, or (ii) is not a Public Utility.

Product M: General Purpose Energy Service

1. Service to be Provided

1.1 This Product provides for the supply of General Purpose Energy by a Seller to a Buyer to enhance economic system operation.

2. Conditions of Service

2.1 To the extent practicable, General Purpose Energy shall be used to improve the overall economy of the systems involved in the Transaction.

2.2 General Purpose Energy shall be supplied through transmission facilities which have adequate capacity for transmitting such energy, in accordance with any applicable reliability standards and procedures.

3. Schedule of Rates

The rates and term for General Purpose Energy shall be negotiated by the Parties arranging the Transaction when the Seller (i) is a Public Utility that has been granted market-based rate authority by the FERC, or (ii) is not a Public Utility.

EXHIBIT A
MID-CONTINENT ENERGY MARKETERS ASSOCIATION
CAPACITY AND ENERGY TARIFF

CONFIRMATION LETTER

This confirmation letter shall confirm the Transaction agreed to on ___________, ___ between ________________________ (as "Seller") and ____________________ (as "Buyer") regarding the sale/purchase of the Product under the terms and conditions as follows:

Schedule P Product:

[] Into ________________, Seller's Daily Choice

[] Firm (LD)

[] Firm (No Force Majeure)

[] Non-Firm

[] System Firm

(Specify System:) ____

[] Unit Firm

(Specify Unit(s): ____

[] Other: ____

[] Transmission Contingency (If not marked, no transmission contingency)

[] FT-Contract Path Contingency [] Seller [] Buyer

[] FT-Delivery Point Contingency [] Seller [] Buyer

[] Transmission Contingent [] Seller [] Buyer

[] Other transmission contingency

(Specify: ____)

Schedule Q Product:

[] Product A – Participation Power Interchange Service

[] Product J – Firm Power Interchange Service

[] Product K – System Participation Power Interchange Service

[] Product L – Interruptible Load Replacement Energy Service

[] Product M – General Purpose Energy Service

Contract Quantity: ______________________________

Delivery Point: ______________________________

Contract Price: ______________________________

Energy Price: ______________________________

Other Charges: ______________________________

Delivery Period: ______________________________

Special Conditions: ______________________________

____

____

____

____

____

____

Scheduling: ______________________________

Option Buyer: ______________________________

Option Seller: ______________________________

Type of Option: ______________________________

Strike Price: ______________________________

Premium: ______________________________

Exercise Period: ______________________________

This confirmation letter is being provided pursuant to and in accordance with the Mid-Continent Energy Marketers Association Capacity and Energy Tariff (the "Tariff") and constitutes part of and is subject to the terms and provisions of such Tariff. Terms used but not defined herein shall have the meanings ascribed to them in the Tariff.

Seller	Buyer
By: ____________________	By: ____________________
Title: ____________________	Title: ____________________
Phone No: ____________________	Phone No: ____________________
Fax: ____________________	Fax: ____________________

EXHIBIT B
MID-CONTINENT ENERGY MARKETERS ASSOCIATION
CAPACITY AND ENERGY TARIFF

SUPPLEMENTARY AGREEMENT

Between

____

and

____

This Supplementary Agreement is made as of __________ ("Effective Date") by ___________ ("Party A") and __________ ("Party B") ("Supplementary Agreement").

Whereas Party A and Party B are MEMA Members and desire to transact in accordance with the terms and conditions contained in the Tariff, as amended, restated or replaced from time to time;

And Whereas, if an to the extent that Party A and Party B carry on business, transact or act pursuant to the Agreement, Party A and Party B wish to make elections with respect to certain options contained in the Tariff, as set forth in this Supplementary Agreement. Such elections shall not, however, apply as between Party A or Party B and any other MEMA Members.

Now therefore, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties agree that if and to the extent that Party A and Party B carry on business, transact or act pursuant to the Agreement, the Parties agree as follows:

1. **Article Three Election - Confirmations**

☐ Written Confirmation
☐ Oral Confirmation
☐ Electronic Confirmation
If Electronic Confirmation is applicable, complete the appropriate specific confirmation provisions below

Specific Confirmation Provisions

(i) Electronic Confirmation Method:
Electronic means of communication to be used by Party A and Party B shall be:

(ii) Other Provisions: (if required)

2. **Article Nine Election - Credit Assurance**

For the purposes of Article Nine, the Parties hereto make the following elections:

Section 9.2 Credit Assurances

☐ Option 1
☐ Option 2
☐ Option 3
If Option 3 is applicable, complete the following:
Downgrade Event for Party A shall mean:____________________
Downgrade Event for Party B shall mean:____________________
☐ Option 4 (see Schedule A)

3. **Guarantors**

Party A:
☐ Not Applicable
☐ Applicable
If applicable, complete the following:
Guarantor for Party A: ____________________

Party B:
☐ Not Applicable
☐ Applicable
If applicable, complete the following:
Guarantor for Party B: ____________________

4. **Amendments to Tariff**

☐ Not Applicable
☐ Pursuant to Section 3.6 of the Tariff, Party A and Party B agree to amend the Tariff as follows: ____________________
____
____

5. **Notices**

Party A:
Address: ____________________
____
____

Attention: ____________________
Telephone No.: ____________________
Facsimile No.: ____________________

Party B:

Address: ______________________________
____
____

Attention: ______________________________
Telephone No.: ______________________________
Facsimile No.: ______________________________

6. **Effect.** This Supplementary Agreement shall be applicable to all Transactions entered into between Party A and Party B pursuant to the Agreement on or after the Effective Date without the need to reference this Supplementary Agreement in any such Transaction unless Party A and Party B mutually agree otherwise with respect to a particular Transaction. Capitalized terms used but not defined in this Supplementary Agreement shall have the meanings ascribed to them in the Tariff.

7. **Entire Agreement.** This Supplementary Agreement constitutes the entire agreement and understanding of the Parties with respect to its subject matter and supersedes all oral communication and prior writings (except as otherwise provided herein) with respect thereto.

8. **Counterparts.** This Supplementary Agreement may be executed and delivery in counterparts (including by facsimile transmission), each of which will be deemed an original.

9. **Authority to Bind.** By signing below, each individual additionally warrants that he or she is authorized to sign this Supplementary Agreement on behalf of the Party for which it was executed.

10. **Headings.** The headings used in this Supplementary Agreement are for convenience of reference only and are not to effect the construction of or to be taken into consideration in interpreting this Supplementary Agreement. In witness whereof, the Parties have executed this Supplementary Agreement with effect from the date above written.

Party A:	**Party B:**
______________________________	______________________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________

Response No. PSC-016
Attachment B

Montana-Dakota Utilities Co. 2010 Capacity and Energy Supply Request for Proposals

August 26, 2010

2010 Capacity and Energy Supply RFP

- 2010 All Resources RFP
- All Resources Qualifying Projects
- All Resources RFP Timeline
- Notices of Intent to Bid & Proposals
- Qualified Respondents
- Proposal Detail

2010 All Resources RFP

Montana-Dakota requests competitive proposals for capacity and energy totaling at least 25 megawatts (MW) and no more than 225 MW for a period of at least five years, with five-year extension options available, beginning power deliveries between June 1, 2015 and May 31, 2020.

All Resources Qualifying Projects

Montana-Dakota will consider Proposals from any qualified Respondent, including electric utilities (e.g., investor-owned, municipal, cooperative, or tribal), independent power producers, qualified developers of generating resources (including renewable resources, distributed generation, and demand-side management (DSM) resources), and power marketers.

All Resources RFP Timeline

- June 1 – RFP issued
- July 8 – Bidder's Conference
- July 23 – Notices of Intent to Bid are due
- August 20 – RFP responses due
- October 1 – Shortlist notification
- November 15 – Selection process completed

Notices of Intent to Bid & Proposals

- At the deadline for submitting Notices of Intent to Bid, July 23, 2010, a total of nine NOIBs received
- Two entities – Xcel Energy and Nebraska Public Power District – sent notes saying they would not be able to bid.
- Two days before the deadline for submitting proposals, August 20, 2010, Global Wind Harvest, the initial developer of Tatanka Wind Farm, called and requested to submit a proposal without having sent an NOIB in advance.
- The proposal from Ameren Energy Marketing was disqualified for refusing to pay proposal submittal fee.
- As a result, we have received qualified proposals from eight entities (see next slide).

Respondents with Qualified Proposals

- Eight respondents, three of which submitted multi-option proposals:
  1. Acciona Energy North America (six-part proposal)
  2. Calpine Corporation (three-option proposal)
  3. CPower
  4. Iberdrola Renewables (two-option proposal)
  5. NextEra Energy Resources
  6. Thunder Spirit Wind, a subsidiary of Global Wind Harvest
  7. Tilton Energy c/o LS Power Development
  8. WE Energies

Proposal Detail – Acciona

- 1. <u>Acciona Energy North America</u>
  - Energy and capacity from the 180 MW Tatanka I wind farm
  - Quantity
    - Energy – ~14% (25 MW/h) to 100% (up to 180 MW/h)
    - Capacity –100% of Local Unforced Capacity (UCAP), ~25 MW
  - Delivery point: MISO CP Node MDU.Tatanka1
  - Term – Acciona proposes six term sheets for
    - All-Hours, Off-Peak Hours, and On-Peak Hours (defined by Midwest ISO)
    - Two time periods:
      - June 1, 2013 through May 31, 2015
      - June 1, 2015 through May 31, 2020

Proposal Detail – Acciona

- Acciona Pricing
  - <u>All-Hours</u>
    - June 2013 – May 2015
      - Energy price: $35/MWh for quantities up to 21% and $43/MWh for quantities greater than 21% of the Product
      - Capacity price: $250/MW-Month
    - June 2015 – May 2020
      - Energy price: $49.50/MWh
      - Capacity price: $1,000/MW-Month
  - <u>Off-Peak Hours</u>
    - June 2013 – May 2015
      - Energy price: $25/MWh
      - Capacity price: $250/MW-Month
    - June 2015 – May 2020
      - Energy price: $30/MWh
      - Capacity price: $1,000/MW-Month
  - <u>On-Peak Hours</u>
    - June 2013 – May 2015
      - Energy price: $54/MWh
      - Capacity price: $250/MW-Month
    - June 2015 – May 2020
      - Energy price: $62/MWh
      - Capacity price: $1,000/MW-Month

Proposal Detail – Calpine

- 2. Calpine – Three proposals
  - The first two proposals are off RockGen Energy Center in Cambridge, Wisconsin, each for 155 MW combustion turbine capacity.
    - Five-year term: June 1, 2015 – May 31, 2020
    - Ten-year term: June 1, 2015 – May 31, 2025
  - The third proposal is off Mankato Energy Center in Mankato, Minnesota
    - Converting the existing 1 x 1 combined cycle unit to 2 x 1 by adding a new combustion turbine and selling the incremental output to Montana-Dakota.

Proposal Detail – Calpine

- Calpine Pricing
  - <u>RockGen Combustion Turbine – 155 MW</u>
    - Delivery Point: Christina Substation; MISO CP Node ALTE.ROCKGEN 1, 2, or 3
    - Five-year term beginning June 1, 2015
      - Capacity price: \$6.25/kW-Month in 2015, escalated at 2.3% annually
      - Energy price formula:

        (Guaranteed Heat Rate x Gas Index) + Variable O&M Payment + Start Charge + Start Fuel Charge

        where:

        Guaranteed heat rate = 10,800 Btu/kWh at 155 MW. Expected12,500 Btu/kWh at minimum output of 100 MW.

        Gas Index = Gas Daily, ANR ML-7, Midpoint in \$/MMBtu for natural gas, plus transmission rate (currently at \$0.35/MMBtu)

        Variable O&M = \$0.75/MWh in 2015, escalated at GDP-IPD annually

        Start Charge = \$8,400/Start in 2015, escalated at GDP-IPD annually

        Start Fuel Charge = 350 MMBtu/Start.
    - Ten-year term beginning June 1, 2015
      - Capacity price: \$6.40/kW-Month in 2015, escalated at 2.3% annually
      - Energy price – Same above

Proposal Detail – Calpine

- Calpine Pricing (continued)
  - Mankato Energy Center – 345 MW
    - Delivery Point: Christina Substation; MISO CP Node NSP.MANKATECG2 and NSP.MANKATECG3
    - Twenty-year term: June 1, 2015 through May 31, 2035
    - Capacity: 345 MW (290 MW of combined cycle + 55 MW of peaking)
    - Capacity price: $10.00/kW-Month in 2015, escalated at 1.5% annually
    - Energy price formula:

      (Guaranteed Heat Rate x Delivered Gas Cost) + Variable O&M Payment + Start Charge + Start Fuel Charge

      where:

      Guaranteed heat rate = 7,250 Btu/kWh based on 290 MW output.

      Delivered Gas Cost = As a toll (MDU-provided gas) or a pass-through priced off Gas Daily, Northern Natural Gas-Ventura Index, Midpoint in $/MMBtu for natural gas, plus applicable transmission rate

      Variable O&M = $1.45/MWh in 2015, escalated at GDP-IPD annually

      Start Charge = $14,500/Start for dispatches of 25 consecutive hours or less, $579/hour for dispatches greater than 25 hours - in 2015, escalated at GDP-IPD annually

      Start Fuel Charge = Hot (<80 hours offline) -1,300 MMBtu/Start, Warm (8-48 hours offline) -2,000 MMBtu/Start, and Cold (>80 hours offline) -3,000 Btu/Start

Proposal Detail – CPower & Iberdrola

- 3. Cpower – Demand-side management program
  - 25 MW of Commercial Load Reduction DSM that would be on-line and available within 24 months of contracting
  - Capacity payment: $4.17/kW-Month
  - Energy rate: $0.30/kWh or $300/MWh
- 4. Iberdrola – Two wind energy options
  - 15-year Power Purchase Agreements
    - 100 MW from the Rugby wind project in Pierce County, North Dakota currently operational
    - 210 MW from the Buffalo Ridge II project in Brookings County, South Dakota expected to be online February 2011
  - Pricing – fixed price
    - Rugby – $51.00/MWh
    - Buffalo Ridge – $55.00/MWh

Proposal Detail – NextEra

- 5. NextEra
  - Two separate wind and nuclear options
    - Wind-only PPA from the Ashtabula III wind project in Valley City, North Dakota
    - Combination of wind and nuclear
      - Wind from Ashtabula III or the Crystal Lake III wind project in Winnebago, Iowa
      - Nuclear from Duane Arnold Energy Center in Palo, Iowa
    - May select to enter a wind PPA without purchasing from Duane Arnold; however, a purchase from Duane Arnold must be combined with wind
  - Ashtabula III
    - 30-year term: COD of December 31, 2010 through December 31, 2040
    - Capacity: 62.4 MW
    - Delivery Point: Minnkota Power Cooperative's 230 kV Pillsbury substation near Pillsbury, North Dakota
    - Pricing
      - $40.63/MWh starting 1/1/2011 or $43.00/MWh starting 1/1/2012, escalating at 2.0% annually.

Proposal Detail – NextEra

- NextEra (Continued)
  - Crystal Lake III
    - 15-year term: January 1, 2011 through December 31, 2026
    - Capacity: 66 MW
    - Delivery Point: Unclear
    - Pricing
      - $42.00/MWh for the first contract year, escalating at 2.25% annually.
  - Duane Arnold
    - Term: 10-year base term of – February 22, 2014 through February 21, 2024; extendable to 2029 and 2034
    - Capacity: 28% of the Duane Arnold facility, or ~172.3 MW
    - Delivery Point: Unclear
    - Pricing
      - Monthly fixed payment = $5,407,116/172,300 =$31.382/kW-Month, multiplied by a monthly "shaping factor" (Jan-1.2, Feb-0.9, Mar-1.1, Apr-0.9, May-1.1, Jun-0.9, Jul-1.1, Aug-1.1, Sep-0.9, Oct-0.8, Nov-0.8; and Dec-1.2), in 2014; escalated at 3.0% annually.
      - Energy charge = $20.00/MWh, multiplied by a monthly "shaping factor" (same as above), in 2014; escalated at 3.0% annually.

Proposal Detail – Thunder Spirit Wind

- 6. Thunder Spirit Wind, a subsidiary of Global Wind Harvest
  - 150 MW wind energy project near Hettinger in Adams County, North Dakota
  - Term: 20-year PPA for 50-150 MW, but open for other alternatives such as co-developing the project
  - Delivery Point: Hettinger 230 kV Substation; have entered the Definitive Planning Phase with MISO
  - Pricing: $39.50/MWh for the first year, escalated at 1.5% annually

Proposal Detail – Tilton Energy

- 7. Tilton Energy, an affiliate of LS Power Development
  - Full output of either two or four LM6000 combustion turbines (~88 MW or ~176 MW Summer) from the Tilton generating facility in Tilton, Illinois
  - Term: 20 years starting June 1, 2015 or earlier
  - Delivery point: Tilton's MISO Commercial Pricing Node AMIL.TILTNCC
  - Pricing
    - Capacity cost: Fixed $2.85/kW-Month
    - Fixed O&M: $1.40/kW-Month escalated at 2% annually, or fixed $1.70/kW-Month
    - Variable O&M: $0.55/MWh in 2015, escalated at 2% annually
    - Emissions cost: passed-through
    - Energy price: Actual heat rate * Gas index

      where:

      Gas index = Day-ahead price per MMBtu shown in "Platt's Gas Daily, Daily Price Survey Midpoint, Chicago city-gates," plus transportation and fuel cost on Midwestern and Ameren LDC; or real-time when available.
    - Fire-Hour Charge: $165/Fired-Hour in 2015, escalated at 2.0%.

Proposal Detail – WE Energies

- 8. WE Energies
  - Capacity and energy sales
    - Using rates calculated by WE's Formula Wholesale Sales Tariff
    - Can purchase between 25 MW and 225 MW in blocks, each block would be in effect for a full year
  - Term: 5-year term starting June 1, 2015
  - Delivery Points:
    - 90% of the energy each hour at WEC.S.CP node
    - 10% of the energy each hour at WEC.N.CP node

Proposal Detail – WE Energies

- WE Energies (Continued)
  - Pricing based on WE's fully embedded average production costs
    - Capacity rate: Currently estimated at $27.70, 28.19, 29.04, 29.91, and 30.80/kW-Month for 2015-2019
    - Energy rate
      - Split into two components: Energy Rate Parts I and II
      - Total energy rate currently estimated at $29.51, 30.48, 31.40, 32.34, and 33.31/MWh for 2015-2019
      - Multiplier to the energy rate: On-Peak – 1.26; Off-Peak – 0.82
  - Payments
    - Charges for capacity and energy
    - True-ups for Energy rate Part I from previous month
    - Credits for WE Tariff "Exhibit C" adjustments for energy and capacity charges
    - Charges for MISO Schedule 17

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

PSC-017
Regarding: Basin Electric seasonal generation redispatch
Witness: Neigum, p. 10

a. **Further describe how the Basin Electric seasonal generation redispatch mitigates potential curtailment due to transmission constraints and the basis for pricing this service.**

b. **Explain whether interconnecting the Lewis & Clark RICE project into the existing WBI Energy pipeline will constrain capacity on that pipeline or otherwise affect service to the Lewis & Clark Station.**

c. **Is the existing WBI Energy pipeline capable of serving a future expansion of the RICE project without constraining pipeline capacity or otherwise affecting service to the Lewis & Clark Station? If not, please explain.**

d. **Provide the analysis that shows construction of the Lewis & Clark RICE project improves system reliability and offsets the need to construct more expensive new electric transmission facilities into the Bakken area.**

Response:

a. Western Area Power Administration's (Western) transmission system in the Bakken Area, of which Montana-Dakota is a transmission customer, is constrained due to the high electric growth rate over the past five years. Western has been unable to provide firm transmission service to all of the new load in the Bakken area. Western has created a new class of transmission service called "less than firm" to reflect new transmission loads which Western has been unable to adequately plan for and construct new facilities to accommodate their new load serving requests. These less than firm load service requests have been prioritized by load forecast submittal dates.

   When transmission system loads exceed predetermined levels whereby local generation is required to run to prevent transmission overloads, transmission customers either need to dispatch available 'new' local generation or curtail customer loads. Montana-Dakota does not have any economical 'new' generation in the Bakken Area, only Lewis & Clark Station on natural gas to produce additional MWs and three 2MW portable diesel generators, to economically redispatch for local transmission constraints in the Bakken Area. Western's Tariff does provide a redispatch option for its transmission customers if Western is unable to fulfill its transmission service requests (i.e. less than firm service). Western is fulfilling its redispatch option by allowing Montana-Dakota to contract with Basin Electric to purchase redispatch or congestion services in the Bakken Area. Montana-Dakota has contracted with Basin for this service over the past several years to avoid customer curtailments or running high cost diesel resources that Montana-Dakota owns in the Bakken Area. Basin prices this service at its marginal cost of fuel at its Culbertson, Pioneer, and Lonesome Creek Generating Stations which it uses to provide redispatching for both its customer loads and those of Montana-Dakota, if excess generation is available. If Basin does not have additional generation available, Montana-Dakota would have to run its higher cost diesel generation resources and/or curtail customer loads as directed by Western.

b. The additional Lewis & Clark Station will not impact service to the Lewis & Clark coal-fired power plant as additional firm transportation is available on the WBI pipeline that runs by the plant.

c. Yes, sufficient natural gas transportation service is available today.

d. Montana-Dakota is transmission dependent on Western Area Power Administration (Western) in the Bakken Area. To minimize impacts and improve reliability for its customers and reduce its exposure to transmission curtailments as a customer of Western's transmission system; Montana-Dakota either needs to (1) build new local generation in the Bakken area, (2) increase its customer demand response programs in the Bakken area, or (3) build new transmission facilities into the area to support its customer loads independent of the Western transmission system. To build new Montana-Dakota transmission facilities into the Bakken area, Montana-Dakota would need to construct new transmission facilities from Beulah or Dickinson, ND to Williston, ND which would still leave Montana-Dakota dependent on the Western transmission system for transmission line outages and is cost prohibitive compared to other alternatives. Please see Mr. Neigum's testimony on Page 11 for further discussion.

The Lewis & Clark RICE Project, along with Montana-Dakota's demand response programs in the Bakken area, are able to mitigate 'less than firm' transmission curtailment events that Western could call upon for Montana-Dakota to take action in the Bakken area. The RICE project will be used to support Montana-Dakota's customer loads in the Bakken area by providing an economical fast-start resource if transmission constraints require mitigation actions. The capacity from the RICE units will allow Montana-Dakota to meet its growing resource adequacy requirement for all of its customers along with an economical peak generating resource in the gas rich Bakken Area.

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

PSC-018
Regarding: Thunder Spirit wind project
Witness: Neigum, p. 13-17

a. **Provide a comparison of the wind costs modeled in the 2013 IRP and the wind pricing associated with the Thunder Spirit PPA executed in October 2013.**

b. **Provide MDU's analysis of the Thunder Spirit and other wind proposals submitted in response to the March 2013 RFP.**

c. **Describe the price increases and other PPA amendments that would have been necessary for Thunder Spirit Wind to obtain financing.**

d. **Provide any economic analysis MDU performed that supports the statement (on p. 15), "Montana-Dakota determined it was advantageous and in the best interest of its customers to consider owning and operating Thunder Spirit as an alternative to the PPA arrangement."**

e. **Describe the differences between the amended PPA MDU executed with Allete Clean Energy and the PPA initially executed with Thunder Spirit Wind, and provide the terms of the Asset Purchase Agreement executed with Allete Clean Energy.**

Response:

a. The purchased wind costs modeled in the 2013 IRP included two (2) twenty-five (25) megawatt blocks of purchased wind for twenty (20) years at a cost of $28 per MWh.

   The October 25, 2013 power purchase agreement with Thunder Spirit wind was for 107.5 MW at a flat purchase cost of $28.32 per MWh for 25 years.

b. The material responsive to this request is confidential. Montana-Dakota will provide this information on a confidential basis upon entry of a protective order by the Commission. Staff has extended Montana-Dakota's deadline to file its motion for protective order regarding this information to Friday, October 9, 2015

c. The material responsive to this request is confidential. Montana-Dakota will provide this information on a confidential basis upon entry of a protective order by the Commission. Staff has extended Montana-Dakota's deadline to file its motion for protective order regarding this information to Friday, October 9, 2015.

d. Please see (1) Mr. Neigum's testimony, Exhibit No. DJN-2, (2) the discussion on page 26 of his testimony for the 2015 Preliminary Base Case (PBC) modeling, and (3) the 2015 IRP which included the Thunder Spirit Wind purchase option as a supply side resource. Please see Attachment A on the enclosed CD for the Company's 2015 Montana IRP Volumes I through IV.

e. The material responsive to this request is confidential. Montana-Dakota will provide this information on a confidential basis upon entry of a protective order by the Commission. Staff has extended Montana-Dakota's deadline to file its motion for protective order regarding this information to Friday, October 9, 2015

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

PSC-019
Regarding: Thunder Spirit, additional EGEAS model runs
Witness: Neigum, pp. 24-26

a. **List the resource alternatives available to EGEAS in the additional modeling runs.**

b. **Provide the timeframe of the additional EGEAS modeling evaluation.**

c. **Provide the timeframe for the preliminary 2015 IRP modeling of Thunder Spirit.**

Response:

a. Please see Mr. Neigum's testimony, Exhibit No. DJN-2. The same resources available in the 2013 IRP with the exception of the updated TSW PPA pricing, the TSW ownership option, and removal of the original owned wind supply side options.

   The 2015 Preliminary Base Case was the same as the 2015 IRP.

b. The additional EGEAS modeling was conducted in October through December of 2014.

c. The preliminary 2015 IRP modeling results of Thunder Spirit were conducted in March and April of 2015 based upon questions from the North Dakota Public Service Commission Staff during the Thunder Spirit Wind Advanced Determination of Prudency filing.

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

PSC-020
Regarding: Market vs. owned resources
Witness: Neigum, p. 29

a. **Provide a comparison of the cost of the WE Energies capacity purchases shown on p. 5 to the MISO-calculated cost of new resources for the years covered by the capacity purchases.**

b. **Clarify whether the simple cycle combustion turbine revenue requirement MISO calculates to determine the cost of new resources includes expected fuel costs or just the fixed costs of the plant.**

Response:

a. We Energies Contract

6/1/12 – 5/31/13	$2,900 per MWmonth
6/1/13 – 5/31/14	$2,900 per MWmonth
6/1/14 – 5/31/15	$2,900 per MWmonth

MISO Cost of New Entry Resource

6/1/12 – 5/31/13	$7.917 per MWmonth
6/1/13 – 5/31/14	$8,234 per MWmonth
6/1/14 – 5/31/15	$7,458 per MWmonth

b. MISO's cost of new entry resources only includes the fixed costs of the plant.

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

PSC-021
Regarding: MISO markets
Witness: Neigum, pp. 30-31

a. **Describe the extent to which MISO conducts footprint-wide long-term integrated resource planning to identify optimal resource expansion strategies.**

b. **What percentage of the retail load within the MISO footprint is served by state regulated vertically integrated utilities such as MDU?**

c. **If MISO produces forecasts of energy and capacity prices for future time periods, provide the most recent forecasts for the area of the footprint covering MDU's service territory and a description of the methods MISO uses to produce the forecasts.**

d. **If MISO does not produce forecasts of energy and capacity prices for future time periods, describe how MDU forecasts prices for MISO market purchases for purposes of long-term resource planning.**

Response:

a. Resource expansion planning is a states right function and MISO has no jurisdiction over resource planning activities and cannot direct an entity to construct a generating resource. Decisions to construct supply side resources are up to generator owners, load serving entities, and their regulatory agencies.

   MISO does run high level footprint resource expansion modeling to estimate impacts on the transmission system and future electric market prices from time to time. These are high level in nature and do not represent the individual needs and plans of local load serving entities.

b. The requested information is not available to Montana-Dakota.

c. The requested information is not available to Montana-Dakota.

d. Montana-Dakota estimates future MISO energy prices by calculating a monthly average MISO energy price based upon a four year average of the historical monthly MISO LMPs and escalating the monthly average prices by five percent per year.

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.

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%

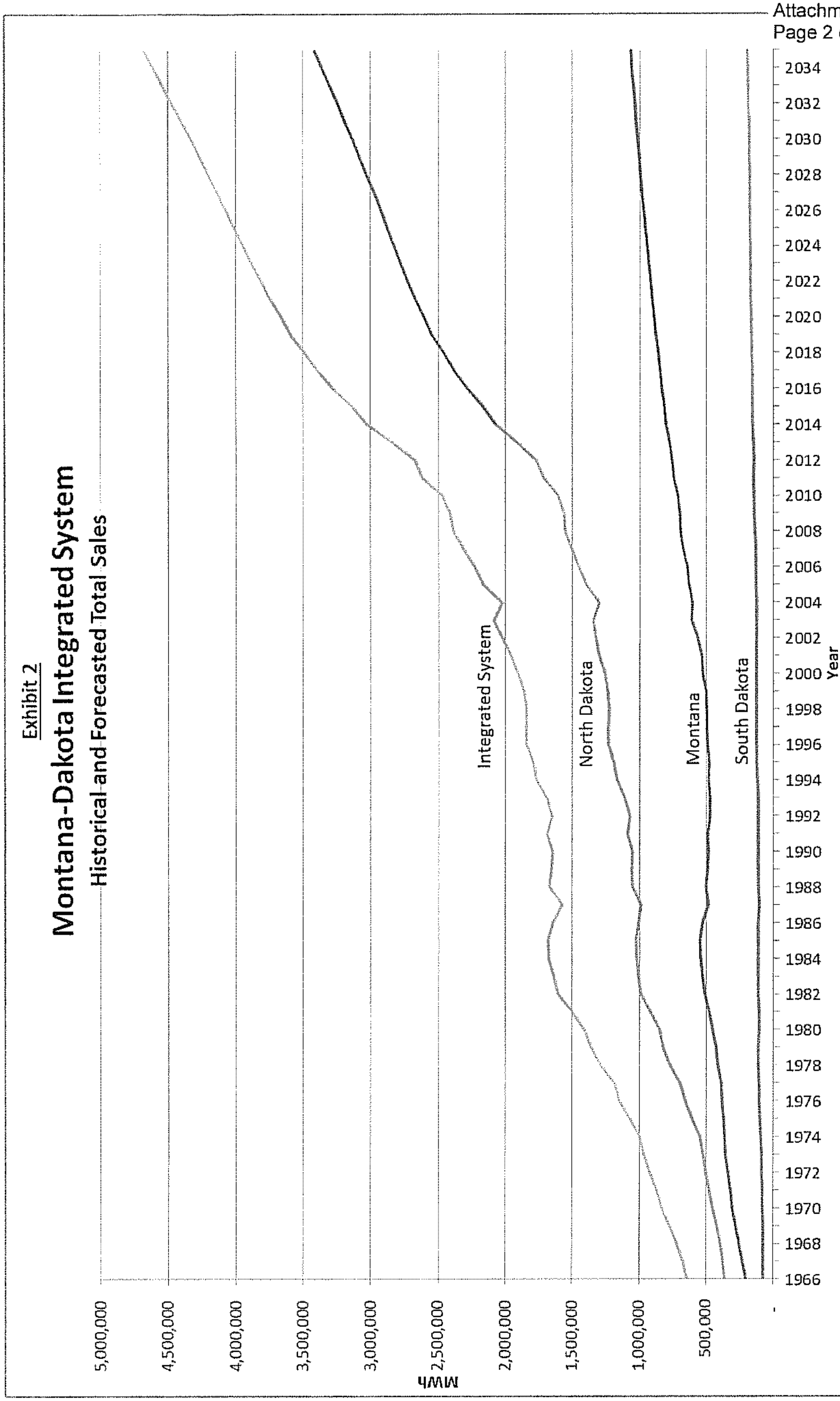
Exhibit 2
Montana-Dakota Integrated System
Historical and Forecasted Total Sales
Integrated System
North Dakota
Montana
South Dakota
MWh
5,000,000
4,500,000
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
Year
1966
1968
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
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1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034

Exhibit 3

Montana-Dakota Integrated System

Historical and Forecasted Sales by Class

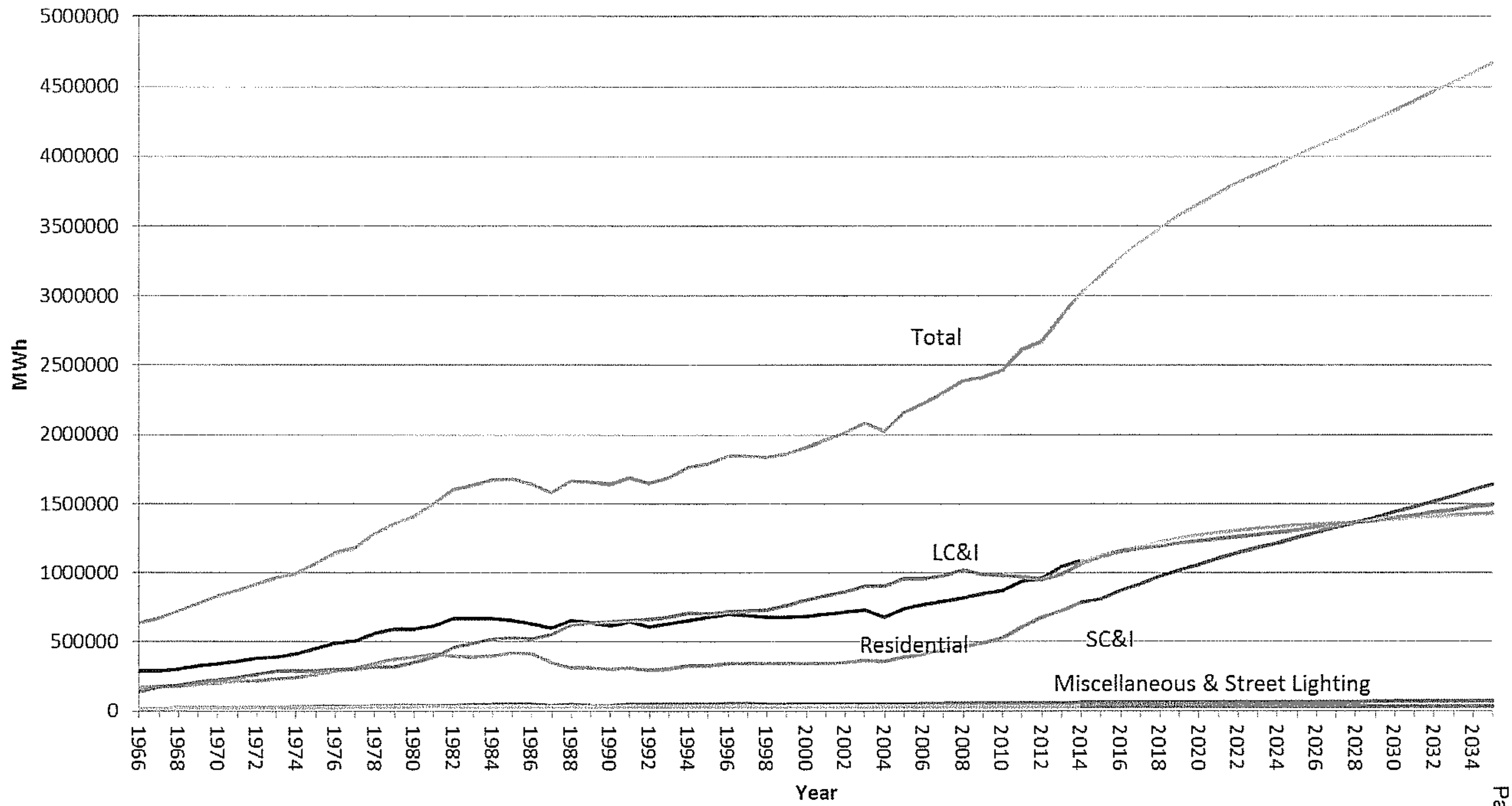

Exhibit 4
Montana-Dakota Utilities Co.
Comparison of 2014 and 2015 Residential Forecasts
Integrated System

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.

18-Apr-13	Towns & REC's	8/9/2010	7/19/2011	7/19/2012	8/28/2013					12/30/2010	1/18/2012	1/31/2013	10/28/2013				
	Hour Ending:	17	17	18	18	Summer	Summer	Summer		18	19	10	20	Winter	Winter	Winter	
	Temp: (Williston/Dickinson)	88/96	99/92	99/100	93/89	2013	2014	2015		-14/-9	-17/-13	-20/-17	25/24.8	2013-2014	2014-2015	2015-2016	
TIOGA1 60KV TIOGA LINE WATT (9414)																	
	Tioga, Ray, Wheelock, Epping, Springbrook	4.30	5.46	6.98	7.20	8.98	9.98	10.98	2,1,1	5.16	8.68	10.81	7.21	13.68	15.68	17.68	2, 2, 2
	REC's	5.69	5.69	11.00	5.94	13.50	13.50	13.50		8.65	13.00	15.88	6.59	16.00	16.00	16.00	
	W.CO-TIOGA	1.45	2.10	2.80	1.96	3.50	3.50	3.50	MWEC	3.38	2.39	2.19	2.65	3.50	3.50	3.50	MWEC
	W.CO-HOFFLUND	1.79	1.49	2.81	3.18	5.00	5.00	5.00	MWEC	2.23	4.08	5.46	3.12	5.00	5.00	5.00	MWEC
	W.CO-RAY	2.45	2.10	5.38	0.80	5.00	5.00	5.00	MWEC	3.04	6.53	8.23	0.82	7.50	7.50	7.50	MWEC
	W.CO-PLSNT VALEY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	MWEC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	MWEC
	Total:	**9.99**	**11.15**	**17.98**	**13.14**	**22.48**	**23.48**	**24.48**		**13.81**	**19.88**	**26.69**	**13.81**	**29.68**	**31.68**	**33.68**	
TIOGA1 60KV BTLVIEW LINE WATT (9412)																	
KNCAID:60KV TIOGA LINE WATT (6603)																	
	Battleview, Powers Lake, Mcgregor, Hamlet, Wildrose	1.04	0.46	1.36	5.83	4.00	4.25	4.50	.25, .25, .25 pl	1.70	2.65	4.87	7.36	5.90	6.15	6.40	.5,.25,.25 plus air liquide
	REC's	2.53	2.91	4.27	1.70	2.70	2.70	2.70		4.09	5.37	2.48	2.16	3.30	3.30	3.30	
	B.D.-BATTLEVIEW	1.89	2.16	3.21	1.70	2.20	2.20	2.20	BD	2.89	3.94	2.48	2.16	2.80	2.80	2.80	BD
	MTRAIL-WT. EARTH	0.63	0.75	1.06	0.00	0.50	0.50	0.50	MWEC	1.20	1.43	0.00	0.00	0.50	0.50	0.50	MWEC
	Total:	**3.57**	**3.36**	**5.63**	**7.53**	**6.70**	**6.95**	**7.20**		**5.80**	**8.01**	**7.35**	**9.54**	**9.20**	**9.45**	**9.70**	
KENMAR 60KV BOWBELLS LINE WATT (6413)																	
KNCAID:60KV KENMARE LINE WATT (6601)																	reset winter 2013-2014
	Bonsness, Bowbells, Lignite Oil Chem Corp, Portal, Flaxton & Northgate	3.43	4.24	5.00	2.34	5.74	6.24	6.74	.5, .5, .5	4.64	7.33	3.97	2.14	6.00	6.75	7.50	1.5, .75, .75
	REC's	3.59	3.58	4.33	5.00	4.50	4.50	2.50		5.43	6.32	7.13	7.35	7.65	3.15	3.15	
	B.D.-KINCAID	0.58	0.68	0.88	1.23	1.00	1.00	0.00	BD	1.19	1.48	1.86	2.21	2.00	0.00	0.00	BD
	B.D.BOWBELLS(2)	0.83	0.88	1.82	1.48	1.80	1.80	1.80	BD	1.28	1.69	1.91	1.99	2.00	2.00	2.00	BD
	B.D.-LIGNITE(2)	1.60	1.35	1.01	1.58	1.00	1.00	0.00	BD	2.09	2.04	2.31	2.16	2.50	0.00	0.00	BD
	B.D.-NORTHGATE	0.58	0.67	0.62	0.71	0.70	0.70	0.70	BD	0.87	1.11	1.05	0.99	1.15	1.15	1.15	BD
	Total:	**7.02**	**7.81**	**9.33**	**7.34**	**10.24**	**10.74**	**9.24**		**10.06**	**13.64**	**11.10**	**9.49**	**13.65**	**9.90**	**10.65**	
KENMAR 60KV MOHALL LINE WATT (6411)																	
OTPDL:Dunning 60KV Xfmr MW (25241)																	reset winter 2013-2014
	Kenmare E. and W. Sub, Tolley, Loraine, Sherwood Mohall Jct Sub	4.62	4.97	4.96	1.30	5.97	6.47	6.97	.5, .5, .5	8.08	9.44	11.08	5.80	12.00	13.00	14.00	.5, .5, .5 - 1, 1, 1
	REC's	4.97	5.50	6.17	6.61	6.25	6.50	6.75	.25, .25, .25	6.96	8.28	8.12	7.21	9.28	9.78	10.28	.5, .5, .5
	N.C.-SHERWOOD	1.39	1.40	1.34	1.63					2.07	2.37	2.45	1.86				
	N.C.-MOHALL	0.95	1.03	1.02	1.12					1.76	1.82	1.93	1.64				
	N.C.-WILEY	2.63	3.07	3.82	3.86					3.14	4.09	3.74	3.70				
	Total:	**9.59**	**10.47**	**11.13**	**7.91**	**12.22**	**12.97**	**13.72**		**15.05**	**17.72**	**19.20**	**13.01**	**21.28**	**22.78**	**24.28**	
ZAHL 60KV GRENORA LINE WATT (10801)																	
GRNORA 60KV ZAHL LINE WATT (5205)																	
	Grenora	0.38	0.59	0.82	0.56	0.99	1.19	1.39	.2, .2, .2	0.60	0.95	1.05	0.70	1.65	2.00	2.35	.35, .35, .35
	REC's	0.44	0.34	0.41	0.40	0.70	0.70	0.70		0.66	0.77	0.82	0.59	1.00	1.00	1.00	
	B.D.-HANKS	0.15	0.14	0.17	0.23	0.20	0.20	0.20	BD	0.32	0.42	0.50	0.42	0.50	0.50	0.50	BD
	W.E.-HANKS	0.29	0.19	0.24	0.17	0.50	0.50	0.50	MWEC	0.34	0.35	0.32	0.17	0.50	0.50	0.50	MWEC
	Total:	**0.82**	**0.93**	**1.22**	**0.96**	**1.69**	**1.89**	**2.09**		**1.26**	**1.72**	**1.87**	**1.29**	**2.65**	**3.00**	**3.35**	
ZAHL 60KV KINCAID LINE WATT (10803)																	
KNCAID:60KV CROSBY LINE WATT (6605)									reset summer 2013								
	Alamo, Corinth, Crossby Noonan, Larson, Columbus	2.02	3.41	2.60	1.98	3.25	3.50	3.75	.25, .25, .25	4.33	6.07	6.63	2.85	7.40	7.90	8.40	1, .33, .5, .5
	REC's	1.61	2.00	2.90	5.26	3.30	3.30	0.30		2.81	4.10	6.64	6.02	5.70	0.70	0.70	
	B.D.-TWIN BUTTE	0.29	0.17	0.25	2.28	0.30	0.30	0.30	BD	0.51	0.45	0.70	2.05	0.70	0.70	0.70	BD
	B.D.-CROSBY(2)	1.32	1.83	2.65	2.98	3.00	3.00	0.00	BD	2.30	3.66	5.94	3.96	5.00	0.00	0.00	BD
	Total:	**3.62**	**5.40**	**5.50**	**7.24**	**6.55**	**6.80**	**4.05**		**7.14**	**10.17**	**13.27**	**8.87**	**13.10**	**8.60**	**9.10**	

TIOGA2 115KV KENMARE LINE WATT (9610)																	
KENMAR 115KV TIOGA LINE WATT (6405)																	
	Stanley	6.47	8.01	11.32	7.17	14.32	16.32	17.32	3, 2, 1 plus ne	6.90	10.91	13.63	7.53	15.91	17.91	24.91	2, 2, 2 plus 5 MW sandpiper Winter 2015-2016
	REC's	8.72	3.73	3.64	1.47	5.50	5.50	2.50		5.74	6.57	5.01	2.17	5.00	3.00	3.00	
	MTRAIL-STANLEY	8.72	3.73	3.64	1.47	5.50	5.50	2.50	MWEC	5.74	6.57	5.01	2.17	5.00	3.00	3.00	MWEC
	Total:	**15.19**	**11.74**	**14.96**	**8.64**	**19.82**	**21.82**	**19.82**		**12.64**	**17.48**	**18.64**	**9.70**	**20.91**	**20.91**	**27.91**	
Kenmare 22 kV line																	reset winter 2012-2013
	Game Refuge, Kenaston Lehman Farm, Coulee, Johnson Farm, Donny Brook & Aureilia, Carpio	1.50	1.08	1.20	1.30	1.28	1.38	1.48	.1, .1, .1	0.76	3.65	2.51	0.90	1.80	1.95	2.10	.15, .15, .15
																	reset to 10 MW growth
Williston - Combinec	Williston	34.61	38.87	44.93	43.27	52.87	59.87	66.87	7, 7, 7	32.05	40.81	47.10	34.87	57.81	67.81	77.81	10, 10, 10
	REC's	7.93	10.80	14.36	11.60	15.00	15.00	15.00		12.83	19.82	16.72	9.32	19.50	21.50	21.50	
	Total:	**42.54**	**49.67**	**59.30**	**54.87**	**67.87**	**74.87**	**81.87**		**44.88**	**60.63**	**65.82**	**44.18**	**77.31**	**89.31**	**99.31**	
WILSTN 60KV NW WILSTN LINE WATT (10220)																	
	NW Sub	21.07	23.61	28.59	29.26					20.04	26.24	22.35	23.3850325				
	NE Sub		Combine Williston														
	REC's			6.36	2.62								3.18				
	W.CO-STONY CREEK	3.45	4.50	6.36	2.62	7.50	7.50	7.50	MWEC	5.65	10.16	6.17	3.18	7.50	7.50	7.50	MWEC
	Total:	**24.52**	**28.11**	**34.95**						**25.68**	**36.40**	**28.52**					
WILLPL 60KV WAPA LINE WATT (10005)																	
	Williston	13.54	15.27	16.35	20.25					12.02	14.57	24.75	18.01				
	REC's				3.63							3.50	3.35				
	L.Y.-TRENTON				3.63							3.50	3.35				
	Total:											28.25					
WILSTN 60KV PCB 3656 WATT (10234)																	
	MonWil REC Williston	4.48	6.29	8.00	5.35	7.50	7.50	7.50	MWEC	7.18	9.66	9.05	2.78698262	12.00	14.00	14.00	MWEC
WAPADL Watford 34KV MDU Tie MW (25014)																	
	Watford City, Alexander Arnegard	**4.65**	**6.01**	**7.58**	**7.33**	**9.51**	**11.51**	**12.51**	**2, 2, 1**	**5.17**	**8.63**	**9.96**	7.48	**12**	**14**	**16**	**2, 2, 2**
						Need to review											
Dickinson - Combine	Dickinson	35.71	38.33	42.09	45.01	58.00	65.00	72.00	15,7,7	32.40	37.81	37.01	46.34	55.00	62.00	69.00	15, 7, 7
	REC's	4.41	4.53	5.50	4.54	5.80	5.80	5.80		4.41	7.77	6.61	5.50	7.70	7.70	7.70	
	Total:	**40.11**	**42.86**	**47.59**	**49.55**	**63.80**	**70.80**	**77.80**		**36.80**	**45.57**	**43.62**	**51.85**	**62.70**	**69.70**	**76.70**	
DICKSN 46KV BELFIELD LINE WATT (3614)																	
	South Diskinson	3.72	4.50	5.70	9.07					7.07	7.50	7.34	10.6956757				
	REC's			5.50	4.54							6.61	5.50				
	W.P.-PATTERSON	4.406	4.532	5.50	4.54	5.80	5.80	5.80	RR	4.41	7.77	6.61	5.50	7.70	7.70	7.70	RR
	Total:	**8.12**	**9.03**	**11.20**	13.61					**11.48**	**15.26**	**13.95**	16.20				
			Combine Dickinson														
DICKSN 46KV DICKSN LINE WATT (3612)																	
	Dickinson Broadway, NE, 21st	24.30	25.69	28.07	16.15					19.47	22.81	12.80	16.7287904				
NDICK 46KV NW DICKSN LINE WATT (7604)																	
	NW Dickinson	7.69	8.15	8.32	19.79					5.85	7.50	16.87	18.9200437				
	REC's				17								19.46972				
	W.P.-LEHIGH				5.39								5.80				
	W.P.-NEW HRADEC				3.89								5.72				
	W.P.-GREEN RIVER				7.72								7.95				
LEWCLK 60KV CULBRT LINE WATT (6814)																	reset winter 2013-2014
	Sidney, Culbertson	16.94	19.42	21.86	19.45	24.86	27.86	30.86	3, 3, 3	17.51	20.67	21.55	17.51	24.55	27.55	30.55	3, 3, 3
	REC's	7.34	8.06	10.32	9.34	9.60	9.60	9.60		7.34	10.46	12.68	10.18	12.30	12.60	12.60	
	SHER-CULBERTSON	1.26	1.61	1.44	1.82	1.50	1.50	1.50	SHE	1.26	1.37	1.59	1.55	1.50	1.80	1.80	SHE

SHER-BAINVILLE	1.43	1.34	1.81	1.46	1.80	1.80	1.80	SHE	1.43	2.26	2.10	1.86	2.40	2.40	2.40	SHE
L.Y.-S.BAINVILLE	0.59	0.68	0.83	1.14	0.90	0.90	0.90	LYR	0.59	0.71	1.16	1.27	1.30	1.30	1.30	LYR
L.Y.-BUFORD	0.94	1.21	1.58	1.06	1.60	1.60	1.60	LYR	0.94	1.46	1.99	1.55	2.00	2.00	2.00	LYR
L.Y.-DORE	0.85	0.80	1.57	0.44	0.80	0.80	0.80	LYR	0.85	1.30	1.62	0.56	0.80	0.80	0.80	LYR
L.Y.-FAIRVIEW	0.80	0.84	1.03	1.12	1.00	1.00	1.00	LYR	0.80	1.20	1.70	1.07	1.50	1.50	1.50	LYR
L.Y.-RIDGELAWN	1.48	1.59	2.06	2.30	2.00	2.00	2.00	LYR	1.48	2.17	2.52	2.32	2.80	2.80	2.80	LYR
Total:	**24.27**	**27.48**	**32.17**	**28.79**	**34.46**	**37.46**	**40.46**		**24.84**	**31.13**	**34.23**	**27.68**	**36.85**	**40.15**	**43.15**	
WAPADL Killdeer 42KV MDU Tie MW (25012)																reset winter 2013-2014
Killdeer, Dunn Center	1.97	2.54	2.68	2.17	3.18	3.68	4.18	.5,.5,.5	4.87	3.40	3.94	2.43	4.94	5.94	6.94	1,1,1
REC's	2.93	3.48	4.99	5.95	5.00	5.00	0.00		2.93	6.08	8.64	6.61	8.90	0.00	0.00	
MKENZ-KILLDEER	1.27	1.27	2.24	2.62	2.20	2.20	0.00	McKenzie	1.27	3.01	4.56	2.77	4.60	0.00	0.00	McKenzie
MKENZ-WERNER SUB	1.19	1.34	1.61	2.07	1.60	1.60	0.00	McKenzie	1.19	1.29	2.32	2.33	2.50	0.00	0.00	McKenzie
MKENZ-HALLIDAY	0.47	0.88	1.15	1.26	1.20	1.20	0.00	McKenzie	0.47	1.78	1.76	1.51	1.80	0.00	0.00	McKenzie
Total:	**4.90**	**6.03**	**7.67**	**8.12**	**8.18**	**8.68**	**4.18**		**7.80**	**9.48**	**12.58**	**9.04**	**13.84**	**5.94**	**6.94**	
Glendive - Combinec Glendive, Wibaux, Beach, Phillips Petroleum	19.25	20.94	23.19	22.53	23.59	23.99	24.39	.4, .4, .4	15.04	16.71	15.50	14.33	17.71	18.21	18.71	.5, .5, .5
REC's	3.50	3.69	5.37	5.90	5.78	8.98	9.48		4.73	5.19	5.00	4.84	10.24	11.24	12.24	
Total:	**22.75**	**24.63**	**28.56**	**28.43**	**29.38**	**32.98**	**33.88**		**19.76**	**21.90**	**20.50**	**19.16**	**27.95**	**29.45**	**30.95**	
GLENDV 60KV MEDORA LINE WATT (4615)																
MEDORA 60KV GLENDIVE LINE WATT (7206)																
Hillcrest sub	8.41	9.41	10.04	9.02	10.24	10.44	10.64	.2, .2, .2	6.83	7.39	7.19	6.20	7.99	8.29	8.59	.3, .3, .3
Wibaux																
Phillips Petroleum																
Beach																
REC's	3.50	3.69	5.37	5.90	5.78	8.98	9.48		4.73	5.19	5.00	4.84	10.24	11.24	12.24	
G.W.-HODGES	0.24	0.24	0.29	0.35	0.30	3.00	3.00	GW	0.46	0.43	0.38	0.30	3.50	3.50	3.50	GW
G.W.-WIBAUX	0.65	0.74	1.55	1.34	1.50	2.00	2.50	GW	1.25	1.33	1.35	1.43	2.20	3.00	4.00	GW
G.W.-GOLVA	0.48	0.53	1.55	1.68	1.80	1.80	1.80	GW	0.82	0.89	0.84	0.66	2.00	2.20	2.20	GW
G.W.-KNUDSON	2.13	2.18	1.99	2.53	2.18	2.18	2.18	GW+RR	2.19	2.54	2.43	2.45	2.54	2.54	2.54	GW+RR
Total:	**11.91**	**13.10**	**15.41**	**14.92**	**16.03**	**19.43**	**20.13**		**11.56**	**12.58**	**12.19**	**11.03**	**18.23**	**19.53**	**20.83**	
GLENCT 60KV GLENDIVE LINE WATT (4411)																
Glendive	10.84	11.53	13.15	13.51	13.35	13.55	13.75	.2, .2, .2	8.21	9.32	8.31	8.13	9.72	9.92	10.12	.2, .2, .2
BEULAH 46KV HALLIDAY LINE WATT (2220)																reset winter 2013-2014
Beulah, Zap	5.38	5.86	6.66	5.82	0.20	0.40	0.60	.2, .2, .2	7.61	8.00	9.42	6.05	9.62	9.82	10.02	.2, .2, .2
REC's	1.05	1.06	0.83	1.51	0.90	0.90	0.90		1.47	1.93	1.61	1.59	2.20	2.20	2.20	
W.P.-MARSHALL	0.45	0.42	0.49	0.61	0.50	0.50	0.50	RR	1.02	1.12	1.15	0.78	1.40	1.40	1.40	RR
W.P.-DODGE	0.60	0.63	0.34	0.90	0.40	0.40	0.40	RR	0.45	0.81	0.46	0.81	0.80	0.80	0.80	RR
Total:	**6.43**	**6.91**	**7.49**	**7.33**	**1.10**	**1.30**	**1.50**		**9.07**	**9.93**	**11.03**	**7.64**	**11.82**	**12.02**	**12.22**	
MEDORA 46KV DICKSN LINE WATT (7209)																
Belfield, South Heart	1.96	2.34	1.74	2.42	3.34	3.84	9.34	.5, .5, 5.5 (refi	2.40	3.36	2.94	0.44	4.86	5.61	10.61	.75, .75, .75 (refinery)
REC's	7.14	7.88	11.29	10.19	11.54	11.79	12.04	RR	10.48	11.88	16.44	***6.89***	14.88	15.38	15.88	RR Need to visit with RR
W.P.-MEDORA												2.41				
W.P.-TRACY MTN												1.06				
W.P.-FRYBURG												1.82				
W.P.-BELFIELD												0.00				
W.P.-ZENITH												1.60				
Total:	**9.10**	**10.22**	**13.03**	**12.61**	**14.88**	**15.63**	**21.38**		**12.88**	**15.25**	**19.38**	**7.34**	**19.75**	**21.00**	**26.50**	
GLNULN 46KV DICKSN LINE WATT (5005)																
DICKSN 46KV GLNULN LINE WATT (3616)																
Gladstone, Taylor, Richardton, Hebron	3.72	3.88	4.01	3.48	4.38	4.63	4.88	.25, .25, .25	3.50	4.08	4.27	2.73	4.88	5.28	5.68	.4, .4, .4
REC's	7.83	8.18	3.46	9.75	8.68	8.93	9.18	RR	9.74	10.21	9.68	***10.00***	11.01	11.41	11.81	RR
W.P.-RICHARDTON												10.00				
Total:	**11.55**	**12.06**	**7.47**	**13.23**	**13.06**	**13.56**	**14.06**		**13.23**	**14.28**	**13.95**	**12.73**	**15.88**	**16.68**	**17.48**	

MDU Load Growth	Total:	147.94	166.40	188.98	179.16	224.47	250.12	278.77		152.70	193.15	206.24	166.68	255.71	287.56	328.66	
	MW Change:					35.49	25.65	28.65	89.79					49.47	31.85	41.10	122.42
	% Change:					18.8%	11.4%	11.5%						24.0%	12.5%	14.3%	
REC Growth	Total REC Load:	69.67	71.42	88.83	85.16	98.76	102.71	90.96		88.25	117.72	125.46	87.01	134.66	118.96	121.36	
	MW Change:					14.41	3.95	-11.75						9.20	-15.70	2.40	
	% Change:					16.2%	4.0%	-11.4%						7.3%	-11.7%	2.0%	

MONTANA-DAKOTA UTILITIES CO.
MONTANA PUBLIC SERVICE COMMISSION
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PSC-023
Regarding: Embedded cost study
Witness: Cardwell, pp. 4-5

a. Provide three-year average (2012 – 2014) annual capacity factors for: 1) MDU's share of the Big Stone Station, 2) the Lewis & Clark Station, 3) the Hesket Station (Units 1 & 2), and 4) MDU's share of the Coyote Station.

b. Provide three-year (2012 – 2014) average monthly energy production figures for the resources listed in part (a).

c. Provide three-year (2012 – 2014) average monthly minimum system loads.

d. Are the resources listed in part (a) primarily energy resources? Why or why not?

e. Explain MDU's decision to allocate production investments related to its baseload coal facilities on the AED factor while allocating production investments related to its wind facilities on a combined energy (80%) – AED (20%) factor.

Response:

a. Capacity Factors

%	Heskett 1	Heskett 2	L&C	Big Stone	Coyote
2012	49.2	63.0	69.0	62.6	59.5
2013	60.0	54.5	81.3	66.0	71.2
2014	59.2	71.5	78.9	61.1	72.9

b. Energy Production (Mwh)

Mwh	Heskett 1	Heskett 2	L&C	Big Stone	Coyote
2012	7,540	32,205	21,154	49,228	46,427
2013	9,200	27,872	24,914	51,948	55,536
2014	9,077	36,529	24,183	48,080	56,861

c. Average monthly minimum loads (Mwh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2012	306	602	251	233	222	224	269	243	223	250	293	325
2013	338	321	313	279	231	229	254	257	145	261	316	382
2014	368	387	338	287	259	241	258	266	255	267	353	357

d. The resources primarily provide both capacity and energy.

e. The AED allocator appropriately recognizes the customer class average requirements as well as the class' demand in relation to the peak demand of the system whereas the allocator used for the wind facilities appropriately recognizes that those facilities are primarily energy related and meeting the energy requirements of each class.

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PSC-024
Regarding: Embedded cost study, Statement L work papers
Witness: Cardwell

The Statement L work papers, pp. L-12 and L-13 show the development of the class AED allocators (Factor 2). Page L-13 indicates that the Montana peak demand of 130,289 KW is a three-year average for July.

a. **Explain MDU's decision to use a three-year average for July.**

b. **Page L-59 in the Statement L work papers shows Montana non-coincident peak demand for the years 2012 – 2014. Explain MDU's decision not to use those non-coincident peak figures in the calculation of the AED allocators.**

Response:

a. Montana-Dakota utilized a three-year average of the coincident peak occurring in July in order to normalize the peak information for purposes of allocating to the classes. The July 2014 Montana peak demand was 140,372.

b. The intent of the AED allocator was to recognize the relationship between the NCP and coincident peak demand.

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PSC-025
Regarding: Average & Excess Demand allocator (factor #2)
Witness: Cardwell

a. **Provide electronic work papers supporting calculation of the class load factors in Statement L, "demand & energy – AED" tab, column E.**

b. **Describe the source and vintage of the data MDU used to calculate the class load factors.**

c. **Explain the process of determining the energy and demand loss factors (columns G & F) in Statement L, "demand & energy – AED" tab.**

d. **To the extent not provided in part (c), explain the higher loss percentage factor for demand.**

Response:

a. Please see Response No. LCG-009.

b. Montana-Dakota selected a random sample of fixed network data from its customer base for periods January – October of 2013 and November-December of 2014 based on data avialability.

c. Please see Response No. LCG-012.

d. Please see Response No. LCG-012.

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PSC-026
Regarding: Allocation factor #3
Witness: Cardwell

a. **You testify that factor #3 is derived by weighting factor #1 by 80 percent and factor #2 by 20 percent. Are the actual proportions 83.5 percent of factor #1 and 16.5% of factor #2?**

b. **Explain MDU's decision regarding the appropriate weightings for factors #1 and #2 in developing factor #3?**

c. **Are the capacity credits for MDU's wind resources listed in Statement L, "Factor 3 Wind" tab the capacity credits MISO attributes to those resources?**

Response:

a. Yes. Please see Response No. LCG-014.

b. Please see Response No. MCC-091.

c. Yes

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PSC-027
Regarding: Embedded cost study
Witness: Cardwell

Explain MDU's decision to apply the AED allocator (factor #2) to all production plant costs, except wind production plant, and particularly whether MDU considered subfunctionalizing its thermal production plant costs based on plant type and service (e.g., baseload vs peaking).

Response:

The AED allocator appropriately recognizes the customer class average requirements as well as the class' peak demand in relation to the peak demand of the system whereas the allocator used for the wind facilities appropriately recognizes that those facilities are primarily energy related and meeting the energy requirements of each class. Montana-Dakota did not consider subfunctionalizng the thermal production plant costs.

MONTANA-DAKOTA UTILITIES CO.
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PSC-028
Regarding: Marginal cost study
Witness: Cardwell, pp. 11-12, Exhibit_(SJC-6)

a. **Explain whether the PLEXOS model includes generation costs from resource additions planned during the 2017 – 2024 study period. For example, do the estimated marginal costs reflect the addition of a Combined Cycle unit in 2020 consistent with the base case least-cost plan identified in the 2015 IRP?**

b. **Explain whether the PLEXOS model includes generation costs associated with the carbon dioxide emissions tax modeled in the 2015 IRP.**

c. **Provide the energy related marginal costs including the carbon dioxide emissions tax modeled in the 2015 IRP, to the extent those costs are not included in Exhibit_(SJC-6).**

d. **Provide work papers showing the total generation related marginal energy and capacity costs allocated to customer classes.**

Response:

a. The PLEXOS model does not include planned resource additions. The model reflects the resources considered in the rate case.

b. The carbon dioxide emissions tax modeled in the 2015 IRP was not modeled through PLEXOS. -

c. The requested information is not readily available. As noted on Page 47 of Volume 1, Chapter 5 of the Company's 2015 Montana IRP, the cost of the carbon tax was included in the dispatch cost of the units when running sensitivity scenarios in EGEAS and not reflected in the marginal energy costs in PLEXOS included on Exhibit__(SJC-6).

d. Please see Response No. MCC-098.

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PSC-030
Regarding: Marginal capacity costs
Witness: Cardwell

a. **In MDU's 2015 IRP, the future resource plan (Vol. 1, p. 54) states MDU will meet short term capacity deficits via the MISO capacity auction or through bi-lateral capacity PPA's. Please explain why MDU has used an 88-MW simple cycle combustion turbine to estimate marginal capacity costs in its marginal cost of service study instead of acquiring capacity through the MISO capacity market or through a PPA.**

b. **Considering the relative uncertainty surrounding the load that MDU will be serving in the Bakken, please discuss the positive and negative aspects of purchasing short-term capacity from the MISO capacity market versus investing in a long-term capacity resource such as an 88-MW simple cycle turbine.**

c. **What is MDU's projected marginal cost of capacity purchased in the MISO capacity market?**

Response:

a. The 88 MW simple cycle pricing represents Montana-Dakota's actual cost of constructing a new capacity resource. MISO capacity market and PPA pricing are subject to availability and timing. In the case of MISO capacity market pricing the actual capacity price is only known in retrospect after the capacity auction clears.

b. Availability of resources and pricing in the MISO capacity auction varies from year to year and is subject to excess capacity resources being available in the auction. It is also subject to zonal capacity requirements and import/export limitations between zones. A capacity auction purchase does not give dispatch requirements to a particular generator nor provide local transmission constraint support during system outages or events.

   Physical resources provide reliability support along with energy dispatch rights. They can also be used to minimize transmission service requirements on the transmission seam between SPP and MISO if the unit is able to be dispatched and avoid the need for additional transmission service.

c. Montana-Dakota does not have a way to forecast future MISO capacity market prices. The Company monitors MISO's forecast of future excess or deficit capacity in the area as an indicator if market capacity purchases will be available. Montana-Dakota considers the capacity auction as an option for short-term and small capacity purchase amounts.

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

PSC-031
Regarding: Environmental Cost Recovery Rider – Rate 98
Witness: Aberle

a. **Define an environmental mandate as referenced in the Applicability section of Rate 98.**

b. **If MDU has an authorized environmental cost recover rider in any of its other jurisdictions, provide the approved tariff schedule(s).**

c. **Is there a cap on costs that could be included in the ECRR, as proposed?**

d. **Would the adoption of the ECRR, as proposed, imply pre-approval of the prudence of costs included in the ECRR? If not, how does MDU propose the Commission vet the prudence or reasonableness of the costs?**

e. **Under a scenario where the Commission approved the ECRR as MDU has proposed and later found the costs included in the ECRR imprudent, how would MDU return the overcharges to customers?**

Response:

a. Environmental mandates would be rulings from the Montana Department of Environmental Quality or the Environmental Protection Agency that resulted in increased costs.

b. Please see Attachment A for a copy of the Company's North Dakota Environmental Cost Recovery Rider Rate 57.

c. Montana-Dakota has not proposed a cap on the costs to be recovered through the ECRR.

d. The adoption of the tariff as proposed in this case does not imply pre-approval of the prudence of costs to be recovered under the ECRR. Montana-Dakota envisions that the ECRR would be submitted with costs to be recovered for specific projects or expenses with full support provided and demonstration that the investment and or expenses are not already included in retail rates. The proposed tariff would then be noticed for comment and Commission decision similar to any other tariff change submitted to the Commission.

e. Please see Response No. PSC-031d. If the costs were implemented on an interim basis and if costs were later determined to be not recoverable appropriate refunds would be made. Simple cost true-ups would be handled through the tracker mechanism

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Electric Rate Schedule

NDPSC Volume 4
3rd Revised Sheet No. 41
Canceling 2nd Revised Sheet No. 41

Environmental Cost Recovery Rider Rate 57

1. **Applicability:**
This rate schedule represents an Environmental Cost Recovery Rider (ECRR) and specifies the procedure to be utilized to recover the jurisdictional costs to be incurred by the Company in complying with federal and state environmental mandates determined to be eligible for recovery under NDCC 49-05-04.2. Costs to be recovered may include capital expenditures, depreciation, taxes, and a current return on the project costs during construction. Costs being recovered under this tariff are currently not included in the rates established at the time of the Company's last general rate case.

2. **Environmental Cost Recovery Rider:**
   a. An adjustment per Kwh will be calculated using the projected capital costs and related expenses, along with the forecasted Kwh sales, to determine a North Dakota jurisdictional revenue requirement to be recovered through the ECRR. The return component of the revenue requirement calculation will be the authorized rate of return from the Company's most recent general rate case.
   b. The ECRR is applicable to all retail customers for electric energy sold, except those served under special contracts, and are allocated amongst the rate classes based on the Company's AED Factor No. 2 established in the Company's most recent general rate case.
   c. The ECRR will be adjusted annually (or other period authorized by the Commission) to reflect the Company's most recent projected capital costs and related expenses for projects determined to be eligible under NDCC 49-05-04.2.
   d. A true-up will reflect any over or under collection of revenue under the ECRR based on actual expenditures from the preceding twelve month recovery period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. **Time and Manner of the Filing:**
Montana-Dakota shall file the ECRR at least 30 days prior to the proposed effective date. The filing by Montana-Dakota shall be made by means of a revised ECRR tariff sheet identifying the amounts of the adjustment, the derivation of the ECRR and the resulting ECRR by class.

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Environmental Cost Recovery Rider Rate 57

4. Environmental Cost Recovery Rider:

Residential and Small General	0.396¢ per Kwh
Large General	0.323¢ per Kwh
Lighting	0.255¢ per Kwh

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

PSC-032
Regarding: Transmission Cost Recovery Rider
Witness: Aberle

a. **If MDU has an authorized transmission cost recovery rider (TCRR) in any of its other jurisdictions, provide the approved tariff schedule(s).**

b. **Is there a cap on the costs that could be included in the TCRR, as proposed?**

c. **Would the adoption of the TCRR, as proposed, imply pre-approval of the prudence of costs included in the TCRR? If not, how does MDU propose the Commission vet the prudence or reasonableness of the costs?**

d. **Under a scenario where the Commission approved the TCRR as MDU has proposed and later found costs included in the TCRR imprudent, how would MDU return the overcharges to customers?**

Response:

a. Please see Attachment A for a copy of the Company's North Dakota Transmission Cost Adjustment Rate 59.

b. Montana-Dakota has not proposed a cap on the costs to be recovered through the TCRR.

c. The adoption of the tariff as proposed in this case does not imply pre-approval of the prudence of costs to be recovered under the TCRR. Montana-Dakota envisions that the TCRR would be submitted with costs to be recovered for specific projects or expenses with full support provided and demonstration that the investment and or expenses are not already included in retail rates. The proposed tariff would then be noticed for comment and Commission decision similar to any other tariff change submitted to the Commission.

d. Please see Response No. PSC-032c. If the costs were implemented on an interim basis and if costs were later determined to be not recoverable appropriate refunds would be made. Simple cost true-ups would be handled through the tracker mechanism.

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Electric Rate Schedule

TRANSMISSION COST ADJUSTMENT Rate 59

1. **Applicability:**
   This rate schedule represents a Transmission Cost Adjustment and specifies the procedure to be utilized to recover the net balance of the capital and operating costs and revenue credits of Montana-Dakota's transmission related expenses and revenues determined to be eligible for recovery in accordance with 49-05-04.3 NDCC. Costs to be recovered under the Transmission Adjustment shall include new or modified transmission facilities such as transmission lines and other transmission related equipment such as substations, transformers and other equipment constructed to improve the power delivery capability or reliability of the transmission system as well as federally regulated costs charged to or incurred by the Company to increase regional transmission capacity or reliability that are not reflected in the rates established in the most recent general rate case.

2. **Transmission Cost Adjustment:**
   a. An adjustment per Kwh will be determined based on the cumulative transmission related costs and revenue credits eligible for recovery and as allocated to the North Dakota jurisdiction as of November 1 of each year and the projected Kwh sales for the recovery period. The adjustment will also include a return requirement on the capital investments based on the authorized rate of return and a true-up of the previous year's adjustment, as described in 2(d).

   b. The adjustment will be applicable to all retail customers for electric energy sold, except those served under special contract and allocated among the rate classes based on the transmission allocation factor from Montana-Dakota's most recent North Dakota general rate case.

   c. The adjustment per Kwh will be revised annually to reflect the current level of costs to be recovered.

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2nd Revised Sheet No. 43.1

TRANSMISSION COST ADJUSTMENT Rate 59

d. The true-up will reflect any over or under collection of revenue under the Transmission Adjustment from the preceding twelve month period plus carrying charges or credits accrued at a rate equal to the three-month Treasury Bill rate as published monthly by the Federal Reserve Board.

3. **Time and Manner of Filing:**
Montana-Dakota shall file the Transmission Adjustment at least 30 days prior to the proposed effective date. The filing by Montana-Dakota shall be made by means of a revised Transmission Adjustment tariff sheet identifying the amounts of the adjustment, the derivation of the adjustment and the resulting Transmission Adjustment rate.

4. **Transmission Cost Adjustment Rate by class:**

Residential & Small General	0.125¢
Large General	0.104¢
Lighting	0.079¢