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December 17, 2015

Dave Glatt
Section Chief
Environmental Health Section
North Dakota Department of Health
918 E Divide Avenue
Bismarck, ND 58501

Subject: **Montana-Dakota Utilities Co. Input on North Dakota's State Plan for Compliance with EPA Clean Power Plan Rule**

Dear Mr. Glatt:

Montana-Dakota Utilities Co. (Montana-Dakota) submits the following recommendations to the North Dakota Department of Health (Department) as North Dakota begins work to develop a state plan for managing North Dakota's compliance under the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan (CPP) Rule. Montana-Dakota appreciates the opportunity to provide input to the Department on the development of the state plan. The Department requested answers to some specific questions public noticed on October 12 that may further guide the Department in its development of a state plan. Montana-Dakota provides as much information as possible below to answer those questions and assist in the process of developing a least cost compliance plan for the State of North Dakota.

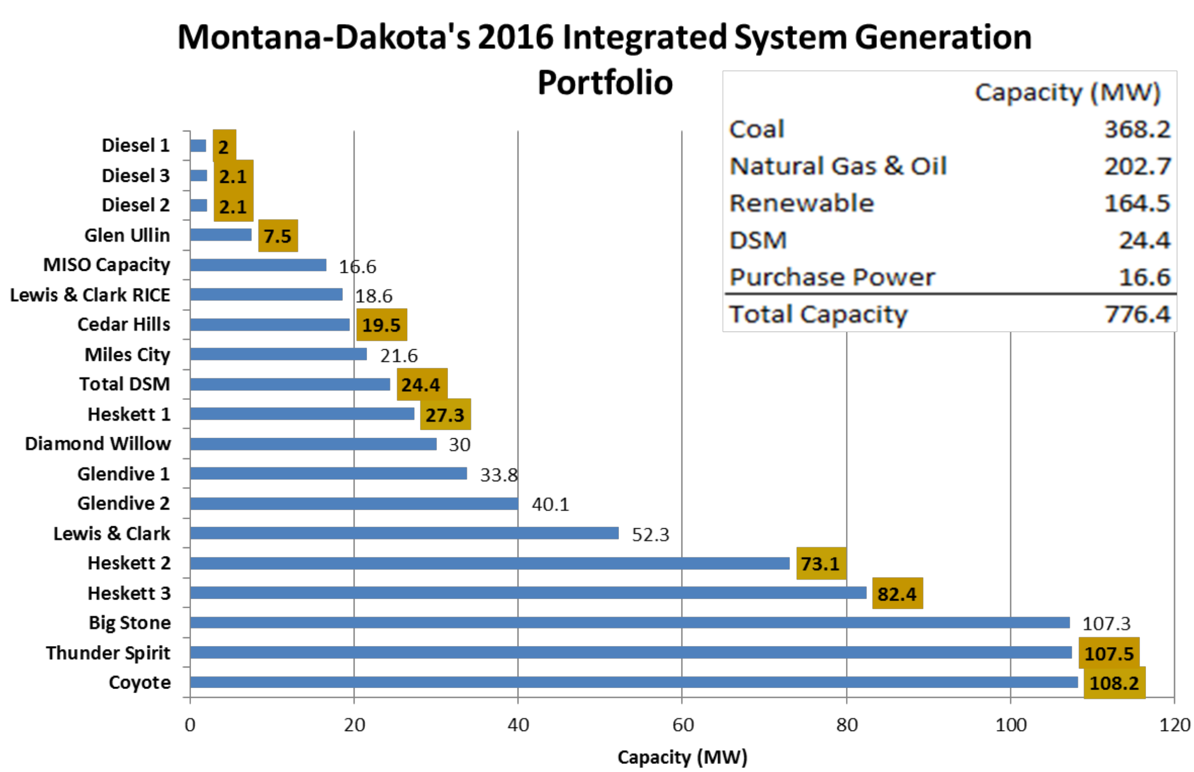
Montana-Dakota is an investor-owned utility company that generates, transmits and distributes electricity to more than 140,000 customers in 179 communities and adjacent rural areas in North Dakota, South Dakota, Montana and Wyoming, with the majority of our customers (78 percent) located in North Dakota. The total capacity of the company's electric generation resources that serve Montana-Dakota's integrated system is about 740 megawatts (Figure 1), and as of December 31, 2015, we project approximately 50 percent of this capacity to be fueled by coal (Figure 2). However, the majority of the electricity delivered to customers is supplied from our affordable coal-fired electric generating resources. By the end of 2016, Montana-Dakota projects the company's coal-fired generation to provide 80 percent of the energy delivered to customers, with about 19 percent of the energy coming from renewable energy resources (Figure 3).

With the majority of Montana-Dakota's coal-fired generating capacity located in North Dakota (approximately 57 percent as derived from Figures 1 and 2), Montana-Dakota has a very significant interest in the options the Department considers in developing a state plan for CPP Rule compliance. Additionally, as Montana-Dakota is an investor-owned utility, and is therefore regulated by state utility regulatory commissions, any significant changes in the generation resource mix resulting from compliance will need to be reviewed and approved by the utility commissions for the company to obtain recovery of these investments.

For more than 25 years, Montana-Dakota has used the integrated resources planning (IRP) process to systematically identify reasonably available demand-side and supply-side resources needed to meet its end use customer's demand for reliable, cost effective, and environmentally responsible electricity. Consumer needs are combined with a least cost analysis to provide a best resource plan which serves as a road map for Montana-Dakota's future generation resources. The Public Service Commissions (PSCs) of both North Dakota and Montana require this IRP process. Montana-Dakota provided detail about this planning process in Appendix E of the Application for a PSD Permit to Construct a Simple Cycle Combustion Turbine at R.M. Heskett Station that was submitted to the Department on November 28, 2012. A copy of Appendix E is attached to this correspondence.

In North Dakota, there is an Advance Determination of Prudence (ADP) pursuant to N.D.C.C. § 49-05-16 and a Certificate of Public Convenience and Necessity pursuant to N.D.C.C. Chapters 49-03 49.03.1 that also guide the ND PSC and Montana-Dakota in making prudent additions of electric generation assets that are in the best interest of the customer. Montana-Dakota would obtain these approvals from the PSC before incurring significant costs for new generation resources to ensure the company can obtain recovery of these investments.

Figure 1



(Beige shading of value indicates the resource is located in North Dakota)

Figure 2

Projected 2016 Capacity Mix

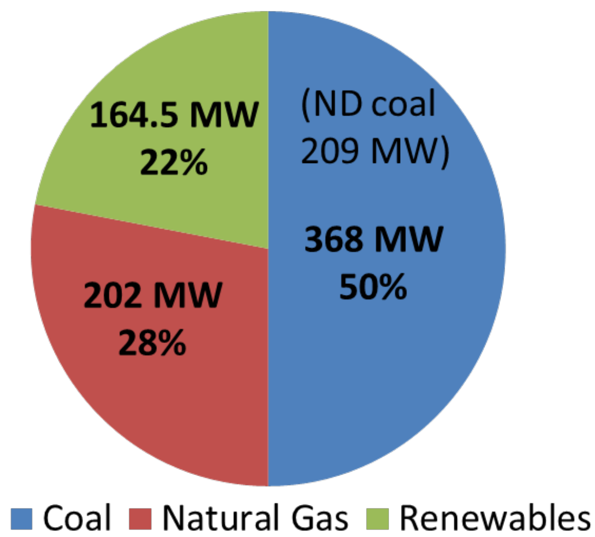
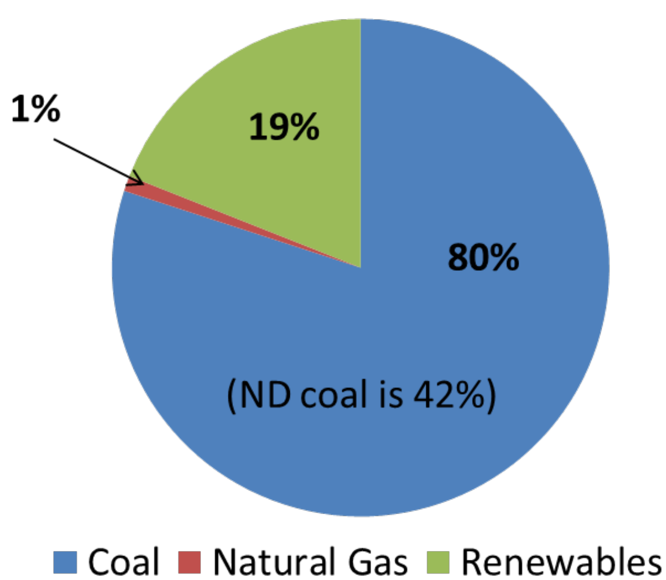


Figure 3

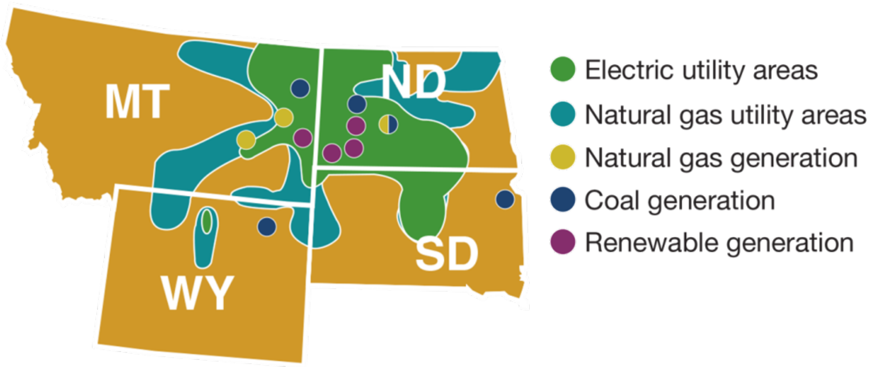
Projected 2016 Energy Delivered



Coal continues to be an economic electric generation resource option in the regions where Montana-Dakota operates, despite low natural gas prices. The company's coal-fired electric generating units (EGUs) provide cost effective and reliable base load electricity to customers.

Figure 4

Montana-Dakota Utilities Co. Generation Locations and Service Territory



There is significant concern with meeting the 2030 final emission target, as well as meeting the stringent targets that would apply as early as 2022. Montana-Dakota anticipates that additional electric and natural gas transmission infrastructure are needed in order to implement the new resources required for compliance with either a mass- or rate-based program. It will take at least five to seven years to install such infrastructure depending on what the state plan requires and where a resource can be sited, permitted and constructed (see Figure 5). If the infrastructure is not in place by the time a new resource is needed, either reliability of the electric system will be at risk or compliance with the CPP Rule may be at risk as the generation required for compliance would not be available and existing units must continue to operate.

Figure 5

ANTICIPATED IMPLEMENTATION TIMELINE
• October 23, 2015 - Final GHG Rule in Federal Register • September 6, 2016 – Project Department's initial submittal to EPA, with allowed two year extension for proposed State Plan • September 6, 2018 – State Plan Submitted to EPA • September 2019 - EPA approves State Plan • 2017 to 2018 - North Dakota Public Service Commission (ND PSC) 2-yr Integrated Resource Plan completed and submitted to commission for proposed generation resources • 2019 – ND PSC issuance of Advanced Determination of Prudence order of new resource implementation and retirement of existing resource if determined a prudent decision by the commission via certification of public convenience and necessity filing • 2019 to 2021 – MISO interconnect and network upgrade study completed for existing resource retirement and new resource – re-evaluate resources and

resource locations depending on network upgrades identified or if major reliability concern identified

- 2020 to 2021 - Obtain major permits and public service commission siting approval
- 2020 to 2025 – Obtain major permits for electric and/or natural gas transmission infrastructure, depending on location, project length and environmental concerns
- 2020 to 2025 – Obtain NEPA Record of Decision, if required
- 2019 to 2022 - Design, engineer, develop bid specifications, award bids and procure resource equipment and receive delivery
- 2022 – Begin resource construction
- 2022 to 2025 – Begin infrastructure construction
- 2025 – Begin resource construction if NEPA review required
- 2025 to 2026 – Commission resource and bring online, depending on infrastructure construction schedule
- 2028 – Commission resource and bring online if NEPA review required

Montana-Dakota has been a member of the Midcontinent Independent System Operator (MISO) since 2003. MISO is an independent system operator and regional transmission operator that provides open-access transmission service and monitors the transmission system across all or parts of 15 states and the Canadian province of Manitoba. MISO's main focus is to maintain transmission system reliability, dispatching generation resources on a least-cost basis throughout the region. MISO's review of CPP compliance options in consideration of reliability and transmission network upgrade needs will be very important.

At the outset, Montana-Dakota stresses that the input provided below is preliminary, and that as more evaluation of compliance options continues, the company's input on some of these topics may change. This is especially true considering the litigation outcome of the rule is unknown, there is presently only a high level understanding of the potential cost of allowances and emission rate credits (ERCs), and we do not know how other states where we have generation resources will develop their state plans. Montana-Dakota will provide supplemental input to the Department as more information becomes available.

<u>Input on the Department's Public Noticed Questions</u>

General Question 1:

1) Should the Department develop a plan? If yes, should it be a "State only" plan or a regional plan?

Montana-Dakota recommends the Department develop a state plan and not rely on the EPA to create a plan for the State of North Dakota. Since Montana-Dakota has coal-fired generation in multiple, adjacent states (Montana, South Dakota and Wyoming), we recommend the Department develop either a “trading-ready” plan or a plan considering adjacent state approaches, incorporating mechanisms to help facilitate interstate emission trading without requiring states to submit joint plans. We believe this approach would be more efficient and result in lower compliance costs.

Montana-Dakota has preliminarily determined that the EPA’s compliance approach as outlined in the agency’s proposed Federal Plan Rulemaking would not be least cost. The higher costs in a Federal Plan are mainly due to EPA’s proposal to limit the period of time allowances are allocated to retired units and requiring a large amount of set-aside allowances be utilized for leakage. Also, in a rate-based compliance approach, the EPA limits what renewable generation or other offsets can qualify to generate an ERC. North Dakota would be able to explore other options for generating ERCs that would be more cost effective for compliance where the EPA may only use what is proposed in the Federal Plan.

General Question 2:

2) To what extent should the Department develop a plan?
    - Only improvements at the power plant (inside the fence line)
    - Complete plan as outlined by EPA
    - Something in-between

At the outset, Montana-Dakota believes the rule lacks legal support for incorporating compliance requirements “beyond the fence”. However, in the event that litigation determines compliance with the very stringent emissions reductions must be met, it will be important for utilities to have the ability to reduce emissions across the electric system and not be limited to reductions at the unit itself.

If litigation limits the methodology EPA applied to create the emissions reductions required by North Dakota and only allowed compliance options that could be installed at the unit, there would need to be a focus on evaluating each source and then apply an achievable “inside the fence line” emission standard. Until the courts issue a legal decision on the rule, Montana-Dakota recommends the Department continue on a path to complete a state plan that considers achievable options at each facility, but also meets the intent of the CPP Rule as finalized, allowing as much compliance flexibility for utilities as possible.

General Question 3:

3) Should the plan be based on:
    - Mass emission limits (mass) - How should allowances be allocated?
    - Emission rate limits (rate) - Uniform rate or uniform percentage reduction?
    - Block 1 - Plant efficiency improvements only?
    - State measures (e.g. plant limits plus demand-side energy efficiency programs)?

Montana-Dakota is still evaluating whether or not a mass or emission rate compliance option would be least cost. In a mass-based compliance program, Montana-Dakota recommends allowances be freely allocated to affected EGUs based on CO_2 emissions. We believe the CO_2 emissions averaged in the 2010 to 2012 time period may be an acceptable averaging period for determining allowance allocation for the company's units. Montana-Dakota is reviewing the averaging period in more detail and will provide additional input to the Department at a future time.

Allowances should be allocated to units in perpetuity, including after retirement of units. Continued allocations would be expected to incentivize retirement of higher emitting units and provide lower cost to utilities and electricity customers as those continued allocations would assist with offsetting the investment in lower emitting replacement generation. Units would not need to continue operating to receive allowances as would potentially be considered if allowances to a retired unit would expire. This methodology is also consistent with other CAA trading programs, such as the Acid Rain Program, which provides "permanent" allowances to affected units.

Further, Montana-Dakota believes that benefits of emission reductions from retirements would not be limited to units that retire after the interim compliance period begins in 2022. Any affected units that are considered by the EPA in the agency's 2012 baseline period and that would retire after 2013, should receive allowances. Allowances should not be denied to units that would retire before 2022.

Allocating allowances based on CO2 emissions ensures that lignite-fired units are not disadvantaged. Lignite coal generally demonstrates a higher carbon content and higher moisture content than other coals, such a sub-bituminous. The additional moisture penalizes the efficiency of electric generation from lignite and the carbon content increases the CO2 emission rate. These characteristics contribute to a CO2 emission rate from lignite-fired units that is approximately 10 percent higher than other coal-fired units.

In addition, Montana-Dakota has implemented heat rate improvement projects at the company's owned and co-owned generating units over time. These projects are implemented when determined to be cost effective and prudent in consideration of cost recovery approval through the utility regulatory commissions. In some cases, efficiency improvements have been either infeasible to implement or cost prohibitive, such as with coal drying. When considering existing plant retrofits, these types of projects can be highly dependent on equipment design margins and physical arrangements. Potential increases in boiler efficiency from implementing a project may be offset by the effects of that project on auxiliary load and negatively impact the heat rate.

In consideration of a rate-based program or applying an emission rate to units, Montana-Dakota interprets that emission rates other than the 1,305 lb CO2 per MWhr applied to coal-fired generation units could result in more flexibility to comply, but would result in a much more complex program for the Department to manage. Further evaluation of this approach may be appropriate if significant flexibility is achieved and where the ultimate cost of compliance would be lower cost for North Dakota. Montana-Dakota is still evaluating compliance options and does not have any recommended approach at this time. As more information becomes available, we will provide it to the Department.

Montana-Dakota has completed some preliminary evaluation of potential energy efficiency savings that could be realized at the customer endpoint. These opportunities will be further explored and reviewed to determine whether savings can be cost effectively achieved and whether the programs could be approved by utility regulatory commissions. To that end, if the Department considers using the "set aside" allowance allocation methodology for compliance in a mass-based program, we would recommend those allowances be allocated to utilities serving customers in North Dakota who could utilize those allowances to assist in offsetting the cost of the programs or for compliance in operating coal-fired generating units.

As the Department considers both mass- and rate-based plans, allowance allocation for the Clean Energy Incentive Program (CEIP) allowances and energy efficiency project ERC generation should be evaluated. Also, as there are several compliance options available in the rule, each having its own level of complexity and that the target is so much more stringent from the proposed rule, Montana-Dakota recommends that the Department file an initial submittal to the EPA in September 2016 that requests the additional two years to explore which option is least cost for North Dakota.

General Question 4:

4) How should the Department incorporate cost and electrical grid reliability concerns into the plan?

Montana-Dakota recommends that the Department engage with a number of entities to incorporate cost and electrical grid reliability concerns with the plan. Some of the entities to include in stakeholder meetings regarding electrical grid reliability are the affected utility companies, Public Service Commission, regional transmission organizations, such as MISO and SPP, and possibly North American Electric Reliability Corporation (NERC) and the Federal Energy Regulatory Commission (FERC) depending on potential impacts expected. Regarding cost concerns, the entities to engage with would be the affected utility companies, coal industry, ND Chamber of Commerce, local coal communities, and the North Dakota Department of Commerce.

Montana-Dakota utilizes an economic dispatch model for planning future resource additions. It is possible that this type of modeling could provide insight into least cost dispatch of units by applying a CO2 allowance price to the emissions of individual units. As existing unit costs increase, new generation resources would be chosen for dispatch and inform when units may need to be replaced. The cost of replacing an existing unit due to CPP Rule costs should be considered in the cost for compliance that a utility or our customers would incur. However, the model does not predict reliability concerns. As compliance options are developed, modeling can be done through MISO or other impacted regional transmission operators (RTOs) to determine whether reliability concerns exist. Other organizations, such as Electric Power Research Institute (EPRI) and possibly other consulting firms, are developing models that could possibly incorporate reliability with least cost.

Many assumptions must be entered into these models, such as cost of allowances/ERCs, allocations of allowances, availability of allowances and there is much uncertainty with estimating values and availability of compliance mechanisms. As mentioned above, Montana-Dakota recommends that the Department continue to engage with specific reliability-governing and impacted utilities as reliability may be a significant concern with the stringent reductions required as early as 2022, as well as in the interim compliance period and beyond.

General Question 5:

5) Should the Department propose any legislation necessary for implementing the plan?

Montana-Dakota does not know if the Department would need to propose any legislation to implement the plan, but believes it is possible that even when implementing the EPA's most straightforward and less complex mass- or rate-based compliance pathways, legislation may be required. For instance in a rate-based program, it would be important for the Department to allow other renewable generation options to qualify for ERCs that the EPA did not identify. In order for the Department to establish certifications of other types of marketable ERCs, or even the ones directly mentioned by EPA such as wind ERCs, state legislation may be needed to recognize those ERCs as a marketable commodity, especially since these have no direct tie to the affected unit for compliance under the Clean Air Act for rulemaking consideration.

The EPA has indicated the agency is developing the platform in which allowance, and possibly ERCs, would be recorded for trading purposes. State legislation may still be needed to enable the Department to provide utilities with the authority to sell allowances to other utilities. Also, legislation may be required to provide the Department the authority to allocate "set aside" allowances to non-affected entities, as the state may give consideration to using EPA's presumptively approvable way of addressing leakage. Montana-Dakota has not researched the Department's authority on allocating the “set-aside” allowances to non-affected entities as the EPA is proposing in the Federal Plan. We recommend the Department conduct legal review to determine whether legislation is needed for the Department to allocate "set-aside" allowances to non-affected entities, and in administering other requirements of the CPP Rule.

General Question 6:

6) Suggestions for cost-effective carbon dioxide reductions.

The Department’s first priority in developing the state plan should be to minimize the economic harm to electric customers in North Dakota, which we believe will be high under any scenario. From a mass-based program perspective, allocating allowances freely to utilities for use in compliance will be most cost-effective. This would be most cost-effective for our customers since North Dakota does not have sufficient allowances to distribute to units in 2022 in order for those units to continue operating as in the past. Allowances will already need to be purchased from other states in 2022 for plants to operate, or generation will be curtailed or retirements will occur. As a retirement may occur, allowances allocated to that retired unit should be perpetual, with those allowances used as needed by the utility to maintain operation of a company’s other coal-fired generating units. The allowances could also be traded or sold by a utility to other affected units in order to help cover the cost of retiring a unit and having to incur expenses to construct and operate a new generation resource. Montana-Dakota does not recommend that the Department use an allowance auction approach.

For a rate-based program, we recommend the Department explore ERC generation opportunities beyond what EPA has included in the proposed Federal Plan Rule.

General Question 7:

7) Comments on EPA’s three building blocks and how they apply to North Dakota sources.

Block 1 is not expected to yield significant and economic emissions reductions as explained in Montana-Dakota's comments on the final rule. Even as EPA reduced their assumptions on the percent achievable heat rate improvement from 6 percent to 4.3 percent, Montana-Dakota commented that this was most likely in the range of 1 to 2 percent for the company’s units.

Regarding Block 2, re-dispatch of coal-fired generation units to existing natural gas combined cycle (NGCC) generation units, Montana-Dakota believes that since there are no existing NGCCs in North Dakota, the EPA should not have used a region-wide assumption for re-dispatch of coal-fired generation to this type of unit. However, we encourage the Department to continue dialogue with EPA on how further compliance flexibility could be gained from the result of this additional stringency in the North Dakota target, while continuing to develop the state plan according to rule requirements.

Montana-Dakota also believes that the EPA erred in using an abnormally high baseline wind generation installation year of 2012 in making the agency's projections for additional renewables that would be implemented in 2022 and thereafter for North Dakota. The Block 3 estimates for renewable resource additions in North Dakota are significant and the transmission infrastructure is not in place to accommodate the amount of renewables the EPA assumes can be added. Montana-Dakota also has concerns with the ability to obtain permits and potential mitigation costs to implement this large amount of renewable generation considering almost the entire state is located within the 95 percentile corridor for the whooping crane which is a threatened and endangered species.

General Question 8:

8) Comments on coordination with the North Dakota Public Service Commission.

Montana-Dakota recommends that the Department consult with the North Dakota Public Service Commission in development of any compliance program that could result in unit retirement and new generation resource requirements as these outcomes overlap with commission jurisdiction. There are significant concerns that stranded assets will result from compliance with the CPP Rule and that additional expenditures will be required for replacement of existing electric generation resources assets. Therefore, it is important for the Department to coordinate with the commission on a regular basis as the plan is developed, especially in consideration of utility company recovery of compliance costs and addressing reliability concerns. We suggest inviting PSC staff to stakeholder meetings on a periodic basis where costs, such as stranded assets costs and replacement generation costs, and reliability are key discussion points.

General Question 9:

9) Comments on coordination with other states.

Montana-Dakota recommends the Department maintain communication with the environmental regulatory agencies in the states of South Dakota, Montana and Wyoming, as the company has coal-fired generation resources in each of these other states which also impacts customers in North Dakota. Also, as discussed above under Question 1, interstate emission trading would be more efficient and result in lower compliance costs.

Block 1 Question 10 (Block 1 of EPA's Clean Power Plan refers to efficiency improvements at the existing power plants):

10) How should the Department consider "remaining useful life" of each plant in the plan?

In determining the remaining useful life of a unit, there are several things to consider. These include depreciation schedules, terms of contractual agreements, pollution control installations, stranded asset costs, replacement generation costs, purpose of generation resource, reliability and possibly more factors.

The remaining useful life should be used to determine how emission standard stringency would be applied on a unit-specific basis. As Montana-Dakota provided in comments to the EPA on the proposed rule regarding consideration of remaining useful life of units, “States should have the authority to consider whether (1) modifications to the timing of compliance or (2) the level of the state goal are necessary to avoid unreasonable economic consequences for power generators and their customers.” Montana-Dakota does not agree that remaining useful life should be used to determine such things as allowance allocations. If any unit, no matter what useful life remains, prematurely retires due to the CPP Rule, it would have to be replaced. Any replacement generation a utility installs would be projected to cost more than what it presently costs to operate an existing reliable and affordable coal-fired generation unit.

Block 3 Question 11 (Block 3 refers to renewable generation replacing existing coal-fired generation):

11) How should the Department incorporate accounting of renewable generation emission rate credits or excess mass allowances into the plan?

- North Dakota takes credit for all renewable generation in the state
- North Dakota takes credit for a certain percentage of renewable generation
- Owners of the renewable power can decide how to use the credits as they see fit

Montana-Dakota recommends that owners retain the rights of the renewable generation emission rate credits produced by their renewable generation and utilize those credits for compliance with their own generation resources in North Dakota or other states, or they would be able to market the credits to others to offset compliance costs. Montana-Dakota believes that this approach would avoid conflicts with interstate commerce clause statutes.

Montana-Dakota does not believe there will be any excess allowances available for distribution beyond what is needed to be allocated to affected sources due to the stringency of the target, unless North Dakota is not successful in supporting that leakage is not occurring with the mass compliance approach. If the Department uses a “set aside” approach to address leakage under the mass program, we believe there is support for limiting allowance allocation to renewables and NGCC re-dispatch under any “set-aside” requirement.

North Dakota should not be required to allocate NGCC allowance “set asides” since there are no existing NGCC units in North Dakota that would need an incentive to increase operation. Also, since there has been a history of significant renewable energy development in North Dakota, even continuing after 2012, we believe there could possibly be support that no “set aside” allowance allocations would be needed to incentivize additional renewables in future. The capacity factors achieved in North Dakota would support lower cost wind development continuing in the state, even possibly without a production tax credit for wind.

There would possibly still be CEIP allowances to allocate under the “set aside” approach. Preliminarily, we believe that those allowances should be allocated to entities that provide energy efficiency programs to end-use customers in North Dakota. These allowances could be used to offset the cost of implementing the energy efficiency programs or for compliance with emissions from coal-fired generation resources.

Block 3 Question 12 (Block 3 refers to renewable generation replacing existing coal-fired generation):

12) Should the Department allow trading of emission rate credits (ERC) or mass allowances (tons of CO_2 emissions)?

- No trading at all
- In-state trading only
- Region wide trading
- Nationwide trading

Montana-Dakota recommends that the Department allow trading at minimum region-wide and believes that the lowest cost compliance would be achieved through nationwide trading. The majority of excess allowances under the CPP Rule appear to be in states on the west and east coasts.

Conclusion:

Without a doubt this is a very complex rule that has created significant challenges. Montana-Dakota believes the first priority should be in developing a state compliance plan that minimizes the economic harm, which we believe will be high under any scenario, to our customers and the state of North Dakota.

While Montana-Dakota fully supports the efforts by North Dakota to challenge the legality of the rule, we believe it's appropriate for the Department to work in parallel to develop and submit a state plan. While creating a state plan, we believe it is important for the Department to continue discussions with the neighboring states of Montana, South Dakota and Wyoming on their respective compliance plan strategies. We also encourage the Department to continue discussions with the PSC on cost impacts to customers.

We do have significant concern with meeting the 2030 final emission target, as well as meeting the stringent targets that would apply as early as 2022. Montana-Dakota anticipates that additional electric and natural gas transmission infrastructure are needed in order to implement the new resources required for compliance with either a mass- or rate-based program. It will take at least five to seven years to install such infrastructure depending on what the state plan requires and where a resource can be sited, permitted and constructed. If the infrastructure is not in place by the time a new resource is needed, either reliability of the electric system will be at risk or compliance with the CPP Rule may be at risk as the generation required for compliance would not be available and existing units must continue to operate.

As previously noted, this is a complex rule and the information provided in this letter is preliminary. As more evaluation of compliance options continues, the company's input on some of these topics may change. This is especially true considering the litigation outcome of the rule is unknown, there is presently only a high level understanding of the potential cost of allowances and emission rate credits, and we do not know how other states where we have generation resources will develop their state plans. Montana-Dakota will provide supplemental input to the Department as more information becomes available.

We appreciate the opportunity to provide this input based on what we know today.

Sincerely,

Abbie Krebsbach
Environmental Director

Enclosure

cc: Nicole Kivisto, President & CEO
Jay Skabo, VP - Electric Supply
Garret Senger, EVP - Regulatory Affairs & CAO
Mike Gardner, EVP - Combined Utility Operations Support
Rick Matteson, Director, Communications & Public Affairs
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Appendix E

Combustion Turbine Project Design & Scope

Appendix E

Montana-Dakota Utilities' CT Project Design & Scope

This proposed project is required to meet Montana-Dakota's capacity requirements beginning in 2015 to support increasing peak power demand and to be capable of load following to support intermittent generator resources such as wind and other renewables. Montana-Dakota Utilities Co. (Montana-Dakota) selected the proposed 88 MW simple cycle combustion turbine generation resource as a result of a lengthy and detailed Integrated Resource Planning (IRP) process, a lengthy regulatory proceeding before the North Dakota Public Service Commission (NDPSC), and a lengthy generator interconnection process and authorization from the Midwest Independent Transmission System Operator, Inc (MISO) and the Federal Energy Regulatory Commission (FERC). Recently, the NDPSC issued its regulatory approvals for the 88 megawatt (MW) project, and the MISO authorized Montana-Dakota to interconnect this specific 88 MW resource to the transmission system at Heskett Station through an executed Generator Interconnect Agreement (GIA).

The Integrated Resource Planning Process

For 25 years, Montana-Dakota has used the IRP process to systematically identify reasonably available demand-side and supply-side resources needed to meet its end use customer's demand for reliable, cost effective, and environmentally responsible electricity. Consumer needs are combined with a least cost analysis to provide a best resource plan which serves as a road map for Montana-Dakota's future generation resources. The Public Service Commissions of both North Dakota and Montana require this IRP process.

In 2010, Montana-Dakota began this IRP analysis to consider all resource options reasonably available to meet the company's identified end-use customer's demand for the 2015 timeframe. Another IRP process is just now beginning in 2012. The IRP process includes four steps: load forecasting, demand-side analysis, supply-side analysis, and integration and risk analysis.

<u>Load Forecasting</u>: The IRP process begins with forecasting Montana-Dakota's customers' future demand for electricity. Based on various factors, a long-term load forecast is developed to estimate the energy requirements and peak demand for twenty years into the future.

Montana-Dakota is a member of the MISO, providing the company's generation resources to a region-wide transmission system operator that coordinates operation of available energy generation to meet electric demand and transmission system stability. MISO requires its members to meet a planning reserve margin (PRM). To meet the PRM, Montana-Dakota must provide sufficient planning resources to cover the company's forecasted monthly peak demand with required MISO adders to reflect losses and margin, referred to as the Planning Reserve Margin Requirement (PRMR). Montana-Dakota utilizes MISO's procedures for calculating the company's available Planning Resource Credits (PRC) from its existing generation options and compares with the PRMR to identify the projected future PRC deficit. This analysis resulted in a projected PRC deficit for the period 2011-2030, which is projected to be 149.5 in 2015 under the base forecast in this IRP process. The PRC value reflects an adjusted electric generation requirement related to MW units.

<u>Demand-side Analysis</u>: Next, feasible demand-side management (DSM) programs are identified. Through customer load management and/or conservation measures, the DSM programs can offset future generation resource requirements. During the IRP process, Montana-Dakota evaluated a number of energy efficiency and demand response programs for its customers in Montana, North Dakota, and South Dakota. Montana-Dakota will implement the DSM programs identified in this IRP over the 2011-2013 period with specific program implementation varying by state. A summary of the proposed DSM program plans by state is provided in Chapter 3 Table 3-3 of the IRP Volume I Main Report.

<u>Supply-side Analysis</u>: The third step in Montana-Dakota's planning process is supply-side resource planning and analysis. In the IRP analysis, these identified resources included Montana-Dakota's existing resources, capacity and energy resources that could be secured through power purchase contracts, a commercial demand response program, an air quality control system (AQCS) project required to continue the operation of the Big Stone Plant, as well as self-build options for simple cycle combustion turbines (SCCT), a combined cycle combustion turbine (CCCT), coal-fired generation, and wind generation.

In analyzing all supply-side resource options available, Montana-Dakota's analysis concluded that a SCCT was the most efficient, cost-effective option available to meet the projected peaking capacity deficit. SCCTs are primarily built to serve peaking capacity needs and are usually used to supply a limited amount of energy because SCCTs are usually fueled by natural gas and/or fuel oil, which may result in higher fuel cost than coal, but lower emissions. SCCT units are lower in capital costs compared to other generating types and can be installed within a relatively short lead time (two to three years). Based on the need to meet peak-time consumer load demands and support renewable resources in 2015, Montana-Dakota determined a SCCT to be the best resource fit for the peaking capacity needs identified in the load forecasting analysis.

A number of business requirements were considered in determining which SCCTs were available to include in the supply-side analysis. First, a review of potential sites for building a SCCT was conducted using transmission system attributes (capability, ability for interconnection to MISO, existing reliability concerns), natural gas system availability (pressure/need for additional compression, possibility for contracting for a firm gas supply), availability of water, synergies with existing generation facilities, land/elevation and other siting considerations as criteria. From review of these attributes, the number of potential sites for a SCCT were narrowed down to three (Richardton, Linton, and Mandan, North Dakota) which all connected to Montana-Dakota's 115kV transmission system. Through review and modeling by the company's System Operations Department of the limitations and reliability needs of the 115 kV transmission system, considering the three sites mentioned above, it was determined that the maximum SCCT design which could be built at all three sites without requiring major transmission upgrades was 100 MVA/95 MW.

Montana-Dakota next looked at nine SCCTs of different types and from different manufacturers. This list was paired down to two design options on the basis of size, response by manufacturers to requests for budgetary pricing, origin of manufacture, delivery dates, and cost. Option 1 was an 88 MW GE 7EA frame-type SCCT and Option 2 was a 43 MW GE LM6000 aero-derivative type SCCT.

The 88 MW GE 7EA and 43 MW GE LM6000 SCCTs were then compared using a number of factors, which led to the conclusion that the 88 MW GE 7EA frame-type SCCT was preferable because of lower per kW capital cost, lower per kW fixed operation and maintenance costs, lower per MWh variable maintenance costs, more robust NO_x control, less off-site maintenance required, lower inlet natural gas pressure requirements, more stable combustion control, less susceptibility to cold weather operational problems, and less technical complexity.

The Mandan site was chosen as the best location for the 88 MW GE 7EA SCCT to meet Montana-Dakota's business requirements, especially since the SCCT would enhance the 115 kV transmission system reliability and ability to serve load in the Bismarck-Mandan, North Dakota area. Additional engineering analysis determined that combination of the proposed 88 MW 7EA SCCT and the Mandan site offers synergies with the nearby Heskett Station operation and determined that the SCCT could be optimized in a combined cycle repower arrangement with the existing Heskett Station steam cycle equipment in the future.

<u>Integration and Risk Analysis:</u> The next step in Montana-Dakota's planning process is the integration and risk analysis. The integration and risk process considers the feasible supply-side and demand-side options to determine a least cost resource expansion plan to economically and reliably meet customer requirements into the future as required by a NDPSC order. A number of scenarios were investigated to determine the sensitivity of their impact on the base expansion plan.

With the exception of the Low Growth sensitivity scenario, which is unrealistic due to current known increased load growth in the Bakken oil field area, the Base Case with New Demand Side Management Package had the lowest Net Present Value and is the basis for Montana-Dakota's resource plans. In this modeled case, two of the larger 88 MW frame-type combustion turbines and none of the 43 MW aero-derivative SCCTs were selected for 2015. Also notable is that the 88MW SCCT was chosen in every single one of the scenarios, except the unrealistic Low Growth sensitivity scenario. In the modeling, the carbon dioxide emissions for the combustion turbine resources are considered indirectly through heat rate and the fuel cost component of the calculated revenue requirements, and carbon dioxide emissions are considered directly through the use of carbon intensities in the Carbon Tax Sensitivity calculations.

The total IRP resource expansion plan, considering the demand-side and supply-side analyses results with the integration and risk analysis, was determined to include the options below:

- Purchase 10 MW of capacity in 2013 and 20 MW in 2014 through the MISO capacity auction or power purchase agreements.
- Contract for a 25 MW demand response program for summer dispatchable commercial or industrial demand response (5 MW in 2012, 15 MW in 2013, and 25 MW in 2015).
- Implement a portfolio of customer demand-side management programs (8.7 MW).
- Install the AQCS equipment required to continue operating the Big Stone Plant.
- Construct two 88 MW frame-type simple cycle combustion turbine to be operational by March 1, 2015.

The outcome of the four step IRP process specifically identified the 88 MW GE 7EA SCCT as the resource generation design for the company to implement in order to meet customer demand, energy, and transmission reliability requirements in 2015, establishing this specific resource as the best business option for Montana-Dakota and its customers, and, therefore, the objective of the proposed project.[1] Through the four step IRP process, Montana-Dakota determined that a combined cycle unit is not feasible to attain its business purposes, due to the specific peaking capacity need identified in the IRP; and Montana-Dakota also determined that an aero-derivative turbine will not meet its business purposes.

IRP Resource Expansion Plan Conclusion

On May 12, 2011, Montana-Dakota filed the IRP, including the best resource plan, with the NDPSC. Based on the analysis of the resource expansion models and the consideration of environmental regulations and the balance of its generation mix, Montana-Dakota's recommended resource plan for the 2011-2015 period was to, among other things, construct one 88 MW GE 7EA frame-type SCCT to be operational by 2015.

Application for Advance Determination of Prudence

On July 7, 2011, Montana-Dakota filed an application for an Advance Determination of Prudence (ADP) pursuant to N.D.C.C. § 49-05-16 and a Certificate of Public Convenience and Necessity pursuant to N.D.C.C. Chapters 49-03 and 49.03.1, to construct, own, and operate an 88 MW frame-type SCCT, the necessary transmission interconnection facilities for the turbine, and the natural gas pipeline to supply the turbine (ADP Application). In the ADP Application, Montana-Dakota explained that a frame-type SCCT was preferred over aero-derivative SCCTs because of lower capital costs, lower operation and maintenance costs, better emission control, ability to perform on-site maintenance, lower inlet natural gas pressure requirements, less susceptibility to cold weather operational issues, and Montana-Dakota's operating experience with frame-type SCCTs compared with aero-derivative SCCTs. Further, Montana-Dakota explained that the site selection process assumed the use of a frame-type SCCT as specified by the IRP process.

On January 10, 2012, the NDPSC held a hearing to consider (1) whether the proposed resource addition is prudent, (2) whether public convenience and necessity will be served by construction, ownership, and operation of the proposed project, and (3) whether Montana-Dakota is fit, willing, and able to provide service. On January 18, 2012, Montana-Dakota filed a copy of a settlement agreement executed by Montana-Dakota and NDPSC Advocacy Staff (Settlement Agreement) recommending the commission's approval of the APD and issuance of a Certificate of Public Convenience and Necessity to Montana-Dakota for the 88MW GE 7EA SCCT.

On April 11, 2012, the NDPSC issued an order that the addition of the 88 MW GE 7EA is prudent (Case No. PU-11-395) and granted a Certificate of Public Convenience and Necessity (Case No. PU-11-398) approving the Settlement Agreement. The order found that the proposed 88 MW GE 7EA SCCT is a prudent resource to meet the needs of Montana-Dakota for electric generation capacity to serve its electric distribution customers, and that it is in the public

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[1] Apart from the IRP process, Montana-Dakota desires to maintain a potential future business option of repowering Heskett units in combined cycle mode with the 88MW unit, since it was determined by analysis that the 88 MW GE 7EA SCCT could be utilized and optimized in a repower arrangement with the existing Heskett Station steam cycle equipment.

interest. The ADP was specific to the type of technology and make/model associated with the 88 MW combustion turbine.[2]

MISO Generator Interconnect Agreement at Heskett

MISO requires a GIA to be implemented for large supply-side resources to connect to the regional transmission system. Montana-Dakota submitted a GIA request to MISO for review of the 88 MW GE 7EA SCCT at Heskett Station on February 8, 2010. This review identified any interconnection facilities as well as network upgrades to the regional transmission system that are determined to be needed in order for the resource to reliably interconnect and deliver energy into the transmission system.

To determine impacts to the transmission system, a specific megawatt rated generator, not a megawatt range, is analyzed by MISO, reflecting the manufacturer's characteristics of a specific generation resource. General industry practice is to request GIAs for a specific-size resource and not a range, since the network upgrade requirements would not be accurate for a range of different generator types and sizes. GIAs require the study of a specific generating unit at a specific site and changes in generator size or characteristic require a new GIA request and study.[2] The MISO GIA was executed on July 30, 2012, was filed with the FERC on August 10, 2012, and confirmation of the FERC's final agency action on the GIA was received on September 27, 2012.

Business Purpose of the Proposed Project

The IRP, NDPSC and MISO analysis led to the CT Project definition, design and selection of the 88MW GE 7EA SCCT and the current PSD permit application. The primary business objectives for the project are to meet a portion of the Planning Reserve Margin Requirement necessary to cover the projected customer peak demand as adjusted for MISO losses and margin (82.3 PRCs provided by the proposed 88 MW GE 7EA SCCT), and the energy requirement as identified in the best resource plan. In addition to the PRC requirement, other business requirements specific to the project include:

- Enhancement of the 115 kV transmission system and load serving capability in the Bismarck/Mandan, ND area. Without the installation of the proposed 88 MW SCCT at the Mandan location, Montana-Dakota would be required to implement load-shedding procedures in the Bismarck-Mandan area under certain contingencies at the Heskett and the East Bismarck substations;
- Avoid MISO transmission system upgrades by limiting the combustion turbine size to 131 MW;
- Use high pressure natural gas as a single fuel from the Northern Border pipeline to provide a firm natural gas supply, avoiding fuel oil as secondary fuel, and avoiding the need for additional natural gas compression;
- Fast start-up capability;
- Fit within size of the proposed project site area. The project site area is limited by surrounding road, drainage ditch, transmission lines, and transmission substations to approximately 5.9 acres;
- Preserve future consideration of using the proposed 88 MW SCCT with one or both of the existing Heskett Station steam cycles in a combined cycle repower. It was determined by analysis that the 88 MW GE 7EA SCCT could be utilized and optimized, from a technical standpoint, in a repower arrangement with the existing Heskett Station steam cycle equipment;
- Ability to perform major engine maintenance on site using Montana-Dakota employees and experienced regionally available contractors. Aero-derivative combustion turbine engines must be sent to a manufacturer's repair depot for major inspection/maintenance increasing outage duration over that required by a frame-type unit;
- Utilize existing Montana-Dakota technical expertise and experience for operation and maintenance. The GE 7EA Auto-tune capability avoids reliance on manufacturer's representatives for frequent combustion tuning to maintain operability and optimum emissions. Aero-derivative combustion turbines must be manually tuned seasonally, at a minimum, and a Auto-tune software solution is not currently offered;

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[2] A redefinition of Montana-Dakota's project as a result of BACT would require Montana-Dakota to abandon the MISO GIA as well as the Settlement Agreement which includes the NDPSC ADP Approval and CPCN. Re-starting the MISO generator interconnection process and NDPSC ADP and CPCN approval processes would result in, at a minimum, the delay of a needed supply-side resource by more than two years.

- Utilize a time proven and robust frame type combustion turbine design. Because they are derived from the aircraft industry, it is Montana-Dakota's opinion and experience that aero-derivative combustion turbines use more exotic materials of construction, tighter design tolerances, and tend to be less robust and reliable than the heavy duty frame type combustion turbines;
- Operate within the historical range of ambient temperatures for the Mandan, North Dakota location of -36 F to 106 F. Montana-Dakota's experience is that extreme cold temperatures cause operability concerns (material thermal expansion, lubrication, and condensation and deposition of natural gas constituents such as even minor amounts of sulfur in the combustion hardware) for aero-derivative units such as the LM6000.

Project Schedule

Montana-Dakota anticipates construction for the CT Project to begin in the second quarter of 2013 (once all of the permits are received) in order to begin commercial operation no later than the first quarter of 2015.