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September 26, 2011

Reply to Fergus Falls office
Direct: 218-998-7152

Mr. Darrell Nitschke
Director of Administration/Executive Secretary
North Dakota Public Service Commission
State Capitol
600 East Boulevard Dept. 408
Bismarck, ND 58505

RE: Revised Attachment 9 and Joint Exhibits 2-3

**Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.
Application for Advance Determination of Prudence Big Stone Air Quality Control
System Project
Case No. PU-11-163**

**Otter Tail Power Company Application for Advance Determination of Prudence
Big Stone Air Quality Control System Project
Case No. PU-11-165**

Dear Mr. Nitschke:

Applicants in the above-referenced matters recently discovered that Burns & McDonnell (the engineering firm that performed the pro forma or levelized-cost economic analysis in Attachment 9 of the Applicants' Application materials) had entered an erroneous heat rate input for Big Stone Plant with AQCS in the spreadsheet analyzing the Big Stone Plant with AQCS vis-à-vis generation alternatives.

The heat rate input was a simple, clerical keystroke-error that resulted in analyzing a higher heat rate than is anticipated for the Big Stone Plant with AQCS. When corrected in the spreadsheet, the busbar energy cost for Big Stone Plant with AQCS is projected to be even lower than the original Attachment 9 reflects – and, therefore, more cost-effective vis-à-vis potential generation alternatives.

For filing we have enclosed an original and seven copies of Revised Attachment 9 and Revised Joint Exhibits 2 and 3, with corrected busbar energy cost figures for Big Stone Plant with AQCS. In order to assist the reader in identify revisions made, we are enclosing both clean and redlined versions of Revised Joint Exhibits 2 and 3.

For convenience of parties and the Commission, Revised Attachment 9 may be substituted for the original Attachment 9. Clean Revised Joint Exhibits 2 and 3 with line numbers may be substituted for Joint Exhibits 2 and 3, as originally filed and as filed on September 7, 2011 with line numbering pursuant to Judge Wahl's order.

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Enclosed materials should be filed in both PU-11-163 and PU-11-165, and I have been authorized by Montana-Dakota Utilities Co. to so advise. Please feel free to contact me if you have any questions.

Sincerely,

/s/ MARK B. BRING
Mark B. Bring
Associate General Counsel

MBB:wao
By electronic filing
Enclosures



September 19, 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
- Interest Rate **[TRADE SECRET DATA BEGINS...**
- Return on Equity
- Discount Rate

...TRADE SECRET DATA ENDS]



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[TRADE SECRET DATA BEGINS...

- o Market Price of Wind Power (2009 \$, excluding PTC)
- o Fuel Cost Forecast

...TRADE SECRET DATA ENDS]
 Table 1

Table 1 – Fuel Cost Forecast

Year	Coal (\$/MMBtu)	Natural Gas (\$/MMBtu)
2016	[TRADE SECRET	
2017	DATA BEGINS...	
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		...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
 - o Net Plant Output 475 MW
 - o Net Plant Heat Rate 10,715 Btu/kW
 - o Net Plant Capacity Factor 75%
 - o Capital Cost of AQCS (2016 \$) \$490 million



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- 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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- Combined Cycle Net Plant Capacity Factor 35%
- Combined Cycle Capital Cost (2010 \$) \$402 million
- Combined Cycle Annual Fixed O&M Cost (2010 \$) \$8.50/kW-year
- Combined Cycle Annual Variable O&M Cost (2010 \$) \$4.30/MWh
- Capacity Factor of Wind Purchases 40%
- 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.



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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 handling 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)	\$ 37.21	\$ 66.44	\$ 66.44	\$ 99.70
O&M	(2016\$ / MWh)	\$ 12.08	\$ 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)	\$ 70.89	\$ 138.50	\$ 103.38	\$ 117.25
Cost of Wind Energy	(2016\$ / MWh)	\$ -	\$ 67.11	\$ -	\$ -
Combined Levelized Energy Cost	(2016\$ / MWh)	\$ 70.89	\$ 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)	\$ 70.89	\$ 104.24	\$ 107.19	\$ 117.25
High Environmental Cost Scenario Adder					
	(2016\$ / MWh)	\$ 3.66	\$ -	\$ -	\$ -
Total Energy Cost Including High Environmental Cost	(2016\$ / MWh)	\$ 74.56	\$ 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



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alternative is the CCGT + Wind option, however, this option results in a 42 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 47 percent. Adding in the high environmental cost scenario adder reduces these differentials in levelized energy costs to 35 percent and 40 percent respectively.

Sensitivity Analysis

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

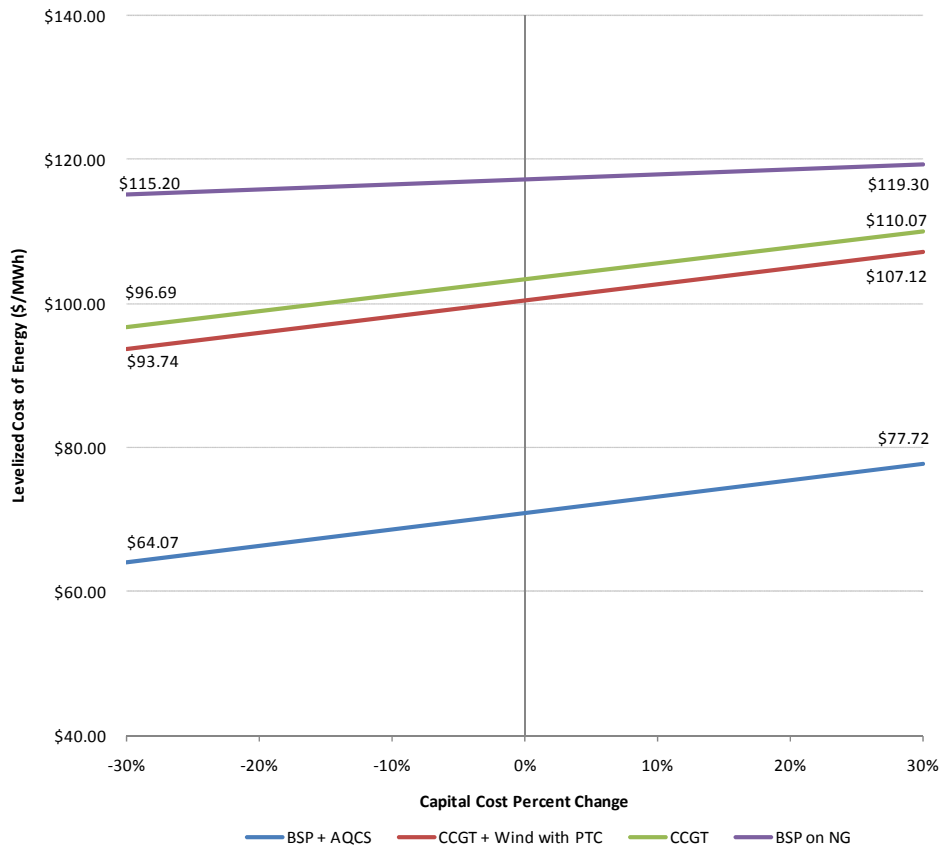
- Capital Cost (plus or minus 30%)
- Fuel Cost (plus or minus 20%)
- O&M Costs (plus or minus 20%)

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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Figure 1 – Capital Cost Sensitivity Levelized Energy Costs



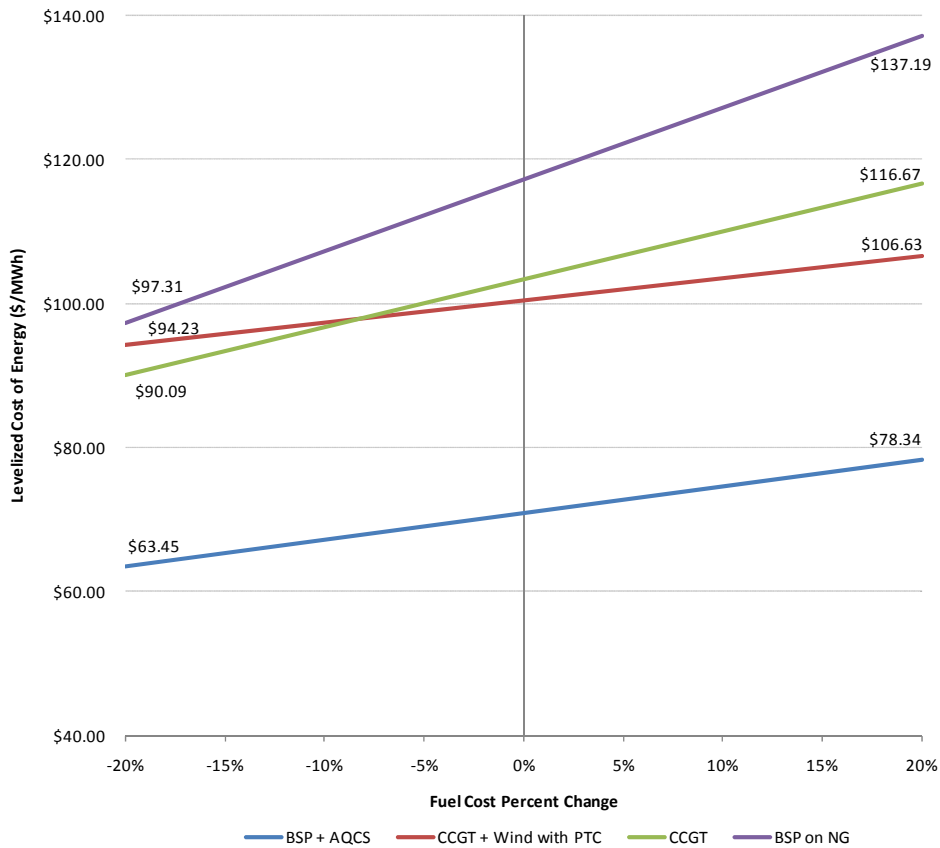
Over the range of capital costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Capital cost changes have a similar impact on BSP with AQCS, CCGT and CCGT + Wind options, since they all have relatively similar capital costs. Capital cost changes have the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



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Figure 2 – Fuel Cost Sensitivity Levelized Energy Costs



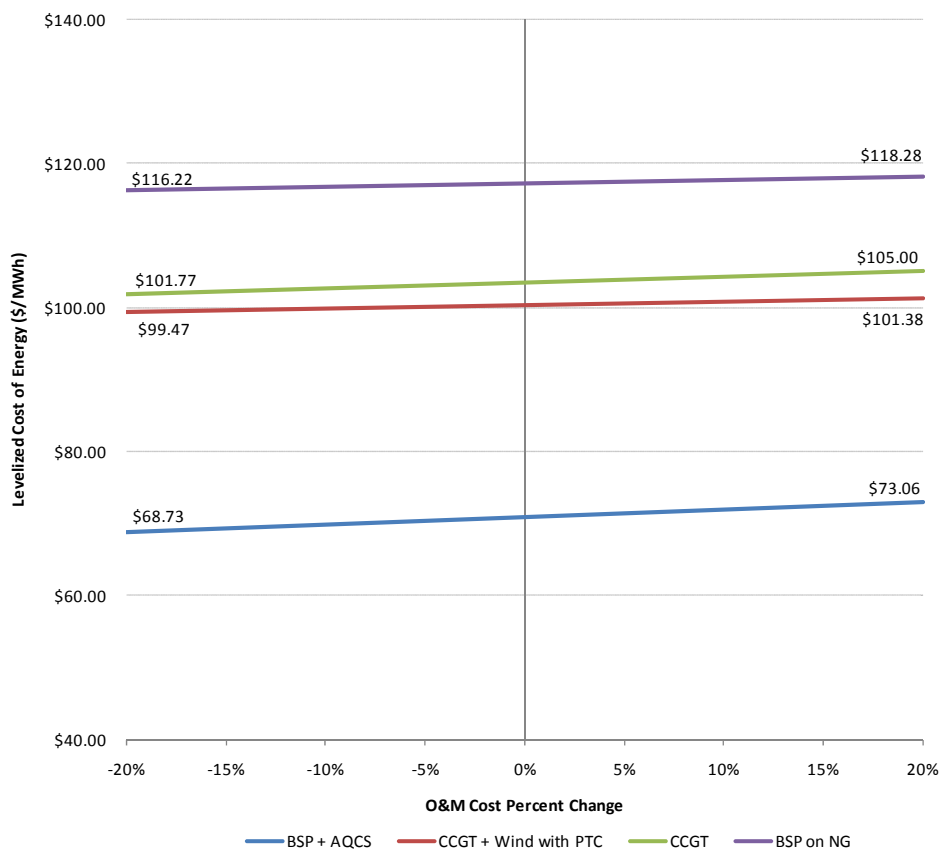
Over the range of fuel costs evaluated in this sensitivity analysis, the BSP with AQCS option is preferred in all instances. Fuel cost changes have the largest impact on the natural gas-fired options, since natural gas has a much higher base case cost than coal. The impact of fuel cost changes is reduced 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.



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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,

A handwritten signature in black ink, appearing to read "Jeff Greig".

Jeff Greig
General Manager, Business & Technology Services

A handwritten signature in black ink, appearing to read "Jeff T Kopp".

Jeff Kopp, PE
Development Engineer

JTK

cc: Mark Rolfes

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

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

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

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

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

27 **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 70.89	\$100.43	\$103.38	\$117.25
Total Energy Cost Including	\$74.38 70.89	\$104.24	\$107.19	\$117.25

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 74.56	\$100.43	\$103.38	\$117.25

1 The Base Case analysis comparing installation of the AQCS with various options for repowering
 2 or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-
 3 effective option, with the cost of the other options at least \$~~29.26~~ per MWh or ~~41~~³⁵% higher than
 4 the levelized MWh cost of the proposed AQCS.³⁰ The AQCS remains the most cost-effective
 5 option under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%),
 6 and O & M cost (+/-20%).

³⁰ Attachment 9 at 6.

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

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

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

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

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

27 **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)	\$70.89	\$100.43	\$103.38	\$117.25
Total Energy Cost Including	\$70.89	\$104.24	\$107.19	\$117.25

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	\$74.56	\$100.43	\$103.38	\$117.25

1 The Base Case analysis comparing installation of the AQCS with various options for repowering
 2 or retiring and replacing the Plant with natural gas shows that the AQCS is the most cost-
 3 effective option, with the cost of the other options at least \$29 per MWh or 41% higher than the
 4 levelized MWh cost of the proposed AQCS.³⁰ The AQCS remains the most cost-effective option
 5 under several sensitivity analyses concerning capital cost (+/-30%), fuel cost (+/-20%), and O &
 6 M cost (+/-20%).

³⁰ Attachment 9 at 6.

1 **III. Joint Exhibit 3 - ASSESSMENT OF FINANCIAL AND OPERATIONAL**
2 **IMPACTS OF PENDING ENVIRONMENTAL REGULATIONS TO THE BIG**
3 **STONE PLANT**

4 The Co-Owners provide this assessment of the financial and operational impacts of pending
5 environmental regulations, including the SD Haze SIP, to the Big Stone Plant. The assessment
6 covers the installation of the pollution controls that comprise the proposed AQCS, as well as
7 other regulatory response scenarios that may be reasonable in view of the costs to comply with
8 the SD Haze SIP, including the retirement or repowering of the Big Stone Plant with natural gas.

9 By installing the AQCS, the Co-Owners customers will continue to receive the benefits of low-
10 cost, reliable electric power from an existing baseload resource, without the need for
11 development of either a greenfield site or new transmission. In addition, as a baseload resource
12 that is frequently used for load following, the Big Stone Plant is a critical resource for a system
13 that is becoming more dependent on wind power and other variable resources. As this
14 Assessment shows, the continued operation of the Big Stone Plant with the addition of the AQCS
15 is a cost effective means to the meet the future needs of the Co-Owners' customers when taking
16 into the account the costs required to comply with the SD Haze SIP and other pending
17 environmental regulations and other viable regulatory response scenarios. The cost estimates
18 and analysis provided in this Assessment were prepared by OTP, on behalf of the Co-Owners
19 with assistance from the engineering firms of Sargent & Lundy and Burns & McDonnell.

20 **A. FINANCIAL AND OPERATIONAL IMPACTS OF PROPOSED AQCS**
21 **PROJECT**

22 The SD Haze SIP determined that BART for the Plant is comprised of a separated over fired air
23 system for the Big Stone Plant boiler to reduce the formation of NO_x, an SCR to chemically
24 reduce NO_x into N₂ and H₂O, a Semi-Dry FGD for SO₂ control, and a baghouse for particulate
25 matter control. The AQCS Project would also include all the ductwork, boiler modifications and
26 infrastructure changes needed to support the required equipment. The AQCS Project is
27 necessary to meet the BART requirements of the SD Haze SIP and its implementing regulations.
28 Without installation of the AQCS, the Plant will not be able to comply with the emission
29 limitations that represent BART, and cannot operate after the deadline for BART compliance has
30 passed.³¹

31 **1. Financial Impacts of Proposed AQCS Project**

32 The estimated capital cost for acquisition and installation of the equipment and support systems
33 for the AQCS is approximately \$489 million (2015 dollars).³² This estimate provides an
34 accuracy range of +/- 20% and is the total project cost escalated to its commercial operation date,
35 which is expected to be late in 2015. Montana-Dakota's North Dakota customers will see an
36 approximate 16 percent increase in rates as a result of its share of this total project cost of \$78

³¹ See ADP Application, Joint Exhibit 1, Section B, Requirement to Implement the Big Stone AQCS Project.

³² See Attachment 5 & ADP Application, Joint Exhibit 1, Section E, Cost Estimate.

1 million. OTP's North Dakota customers will also see an approximate 16 percent increase in
2 rates as a result of its share of this total project cost of \$108 million.

3 The estimated additional increase in the Plant's operation cost in 2016, the expected first full
4 year of operation, associated with the operation of the AQCS, will be approximately \$11 million
5 (including escalation from 2010 dollars).³³ The additional operating expense will increase the
6 cost to produce a MWh of energy by approximately \$3.50, or \$.0035 per kWh, based on the
7 Plant's net dispatchable energy generation of 3,120,750 MWh. After the AQCS is installed and
8 in operation, the estimated total operating cost for the Plant in 2016 is \$27.3 million,³⁴ with
9 Montana-Dakota's North Dakota share being approximately \$4.0 million and OTP's share of
10 approximately \$6.0 million. The biggest operational cost increase will be due to the cost of the
11 lime and ammonia necessary to operate the SCR and semi-dry FGD and the addition of
12 employees at the Plant.³⁵

13 Beyond the additional cost to install and operate the AQCS, additional capital and operating
14 costs are likely to be required in response to anticipated regulations for control of mercury
15 emissions and disposal of coal combustion residual (coal ash).³⁶ The addition of control for
16 mercury, which is likely to be required during the same timeframe as the AQCS Project, is
17 estimated to result in additional capital cost of approximately \$5 million³⁷ and an additional
18 operating cost of approximately \$2 million per year.³⁸ The estimated cost to comply with
19 regulations relating to mercury control will add approximately \$0.65 to the cost to produce a
20 MWh of energy, or \$.00065 per kWh.

21 Table 1 contains a summary of the potential anticipated financial impacts of the proposed AQCS,
22 mercury emission standard, and the potential cost of coal ash regulation.

23

33 Attachment 6.

34 Attachment 6.

35 Attachment 4, Section 6.

36 In addition to the requirements for the AQCS, the Assessment of Financial and Operational Impacts of Pending Environmental Regulations to the Big Stone Plant considered potential cost of new environmental regulations applicable to the Big Stone Plant relating to mercury emission limits and coal ash disposal.

37 Attachment 5, ACI Estimate.

38 Attachment 6.

1

Table 1 – Anticipated Financial Impacts

	Capital Cost (2015\$)	Annual O & M Cost (2016\$)	Levelized Cost (2016\$/MWh)
Big Stone + AQCS	\$489 million ³⁹	\$27.3 million ⁴⁰	\$74.38 70.89 ⁴¹
Mercury Control and Coal Ash Disposal ⁴²	\$5 million	\$8.7 million	\$3.66 ⁴³

2

3

4

2. Operational Impacts of Proposed AQCS Project

5 Apart from capital and increased operating costs, the installation of the AQCS will not have any
 6 significant impacts on the capacity or day-to-day operations of the Big Stone Plant, except for
 7 one longer than typical outage in 2015 to connect the AQCS into the Plant once the AQCS
 8 systems have been constructed. However, there are certain challenges that are being addressed
 9 in the design of the proposed AQCS Project and that have been included in the cost estimates for
 10 the AQCS.

11 First, some modifications need to be made to the boiler to allow for effective operation of the
 12 SCR. The SCR provides effective control of NO_x emissions, but it operates well only within a
 13 specified temperature range.⁴⁴ The boiler temperatures must be maintained so they are neither
 14 too hot at full load nor too cold at low loads. To ensure that proper temperatures are maintained,
 15 the Plant's boiler will need to be modified.⁴⁵ The boiler efficiency is expected to improve as a
 16 result of the modifications, and the hourly boiler heat input will not increase above the current
 17 permitted levels.

18 The design of the AQCS equipment must also allow the Plant to maintain its current ability to
 19 follow load. Varying load conditions must be taken into account in the design of the semi-dry
 20 FGD and SCR. Currently, the Plant will run in a load following arrangement for much of the

³⁹ Attachment 5.

⁴⁰ Attachment 6.

⁴¹ Attachment 9 at 6, Table 2.

⁴² The addition of mercury control equipment is estimated to cost approximately \$5 million, Attachment 5, ACI Estimate, and the annual O & M cost for the mercury control equipment is estimated to be \$2 million, Attachment 6. The increased costs for disposal of coal ash could be as high as approximately \$6.7 million per year, based on a \$37.50 per ton estimate for disposal, including both capital and operating costs. Section IV; *Special Reliability Assessment: Resource Adequacy Impact of Potential U.S. Environmental Regulations*, at 57, NERC (October 2010).

⁴³ Attachment 9 at 5-6.

⁴⁴ Attachment 4 at 3-4.

⁴⁵ Attachment 4, Section 3.2, describes boiler modifications that are anticipated to be needed as a result of the AQCS Project.

1 spring and fall. For example, on a typical spring day when the demand for electricity is
2 relatively low, the Plant is likely to see minimum load at night, but as the electrical load starts
3 increasing, the output of the Plant will rise until it reaches full load during the peak load periods,
4 and then drop off as the electric load drops off at night, eventually getting back to the minimum
5 load for a few hours before repeating the cycle. The design of the AQCS equipment will assure
6 that the ability of the Plant to follow load is not compromised and that the AQCS Project does
7 not decrease the range of load at which the unit may efficiently and safely operate. For example,
8 the AQCS Project will be designed to minimize the duct distance between the semi-dry FGD and
9 the baghouse to limit the amount of ash depositing in the duct work at low loads. Other design
10 considerations involve ensuring that proper temperatures are maintained and that equipment is
11 the appropriate size to operate at both low and full loads.⁴⁶

12 Other operational impacts of the AQCS Project will include the addition of employees to operate
13 and maintain the Plant with the additional equipment.⁴⁷ OTP will provide training on operation
14 of the new equipment to the new employees. Additionally, operation of Big Stone following
15 installation of the AQCS will produce a greater volume of ash to be disposed of because the
16 addition of the semi-dry FGD will result in ash that is less dense than the ash currently produced
17 by the Plant. OTP has sufficient capacity in its existing disposal site for this ash.⁴⁸

18 **B. ALTERNATIVE RESPONSE SCENARIOS**

19 **1. Selection of Alternative Response Scenarios**

20 OTP, on behalf of the Co-Owners has focused on the identification of alternative scenarios that
21 involve either the retirement and replacement or the repowering of the Big Stone Plant. In view
22 of the specific requirements set out in the SD Haze SIP and its implementing regulations, there is
23 only one response scenario that involves the installation of pollution control equipment and that
24 scenario is the proposed AQCS Project. In addition, the use of pollution allowances is not a
25 viable compliance approach because there are no pollution trading programs available that can
26 substitute for BART compliance and address the underlying regulatory concern for visibility in
27 Class I areas.⁴⁹

28 OTP, on behalf of the Co-Owners, assessed the current status of Greenhouse Gas Regulatory
29 requirements when considering alternatives. Congress has considered, but has not adopted,
30 legislation which would require a reduction in Greenhouse Gas (GHG) emissions. However,

⁴⁶ Attachment 4 at 2-5.

⁴⁷ Attachment 4 at 6-1.

⁴⁸ *Id.* at 3-22.

⁴⁹ Emission trading of SO₂ and NO_x may have limited potential to be an option for plants located in the Transport Rule's control zone, subject to affected state decisions in their regional haze SIPs, but South Dakota is not a state proposed for inclusion under that rule. Emission trading of SO₂ under the Acid Deposition Program is in addition to, and does not affect the requirement to comply with other CAA program requirements, such as the regional haze program. 42 U.S.C. § 7651b(f) (CAA § 403(f)).

1 there is no legislation under active consideration at this time. The EPA is proceeding to regulate
2 GHGs under a number of provisions of the Clean Air Act beginning with regulation under the
3 Prevention of Significant Deterioration (PSD) and the Title V permitting process in January
4 2011. OTP does not anticipate making modifications at Big Stone as part of the AQCS project
5 that would trigger PSD requirements, including for GHGs. Consequently, GHG emissions are
6 not projected to trigger the need for a PSD permit as a result of the AQCS Project.

7
8 EPA has announced a timeframe for developing New Source Performance Standards (NSPS) for
9 GHGs from electric generating units. EPA plans to propose this NSPS in August 2011, and
10 adopt the standard in June 2012. In general, NSPS become applicable to new sources built after
11 the effective date of the regulation, or affect what may be required to be included as an emission
12 control at the time an existing source makes a change significant enough to trigger NSPS
13 applicability. To trigger the applicability of NSPS, an existing source must make a modification
14 that increases its maximum hourly emissions rate. The Co-Owners do not anticipate making a
15 modification at Big Stone Plant that would trigger NSPS requirements. The Big Stone AQCS
16 Project is not projected to trigger the applicability of the NSPS for GHGs that EPA plans to
17 develop.

18
19 At the same time EPA develops the NSPS, EPA also plans to issue emission guidelines for
20 existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike the
21 NSPS, applies to an existing source. States are given a period of time to develop plans to
22 implement a 111(d) Standard, and if a state does not develop such a plan, EPA will prescribe a
23 plan for that state.

24
25 While the potential impact of a 111(d) standard on Big Stone is not yet known, standards of
26 performance for GHGs, especially for existing sources, are anticipated to focus on efficiency
27 improvements rather than add-on controls. The Co-Owners have in the past implemented
28 efficiency measures at Big Stone through installation of a more efficient steam turbine at the
29 Plant. The capital cost of efficiency improvements could be offset in whole or in part by reduced
30 fuel costs.

31
32 To identify potentially viable alternatives for economic evaluation, OTP, on behalf of the Co-
33 Owners first identified the needs currently served by the Big Stone Plant, as well as the basic
34 operating characteristics of the Plant. The Big Stone Plant is a key baseload asset for its three
35 utility Co-Owners, serving the existing load of customers in several states. The Plant is the
36 largest baseload resource for each of the Co-Owners. Given the critical resource role played by
37 the Big Stone Plant, OTP, on behalf of the Co-Owners developed alternatives that were capable
38 of reliably: (1) producing approximately 3 million megawatt-hours of electricity per year;
39 (2) serving as a baseload resource, with the ability to follow load and be a dispatchable resource
40 with high availability; and (3) being in operation prior to expiration of the deadline for Big Stone
41 to comply with the BART requirement. Analysis performed by the Midwest Independent
42 Transmission System Operator (“MISO”) has assumed the presence of a baseload generation
43 source at the Big Stone site, and any change in location would require a reevaluation of the
44 transmission system.

45 Given the significant customer load served by the Big Stone Plant, the Co-Owners identified
46 coal, hydropower, nuclear and natural gas as practical potential replacement options that could

1 meet the above criteria.⁵⁰ Since the proposed AQCS Project includes continuation of coal
2 generation at the Plant, another coal option was not considered as an alternative response
3 scenario. Hydropower and new nuclear generation were rejected because expected permitting
4 difficulties suggest that these resources could not be available in the timeframe required for
5 compliance with the SD Haze SIP and its implementing rules and because the size of these
6 alternatives to be economic, would exceed the needs of the Co-Owners. Based on these
7 considerations, it was determined that natural gas was the only viable retirement/replacement or
8 repowering option that could potentially replace the current functions of the Big Stone Plant in
9 the required timeframe.

10 With respect to natural gas, three different scenarios were assessed:

- 11 1) Converting the existing Big Stone boiler to natural gas
12 combustion;
- 13 2) Constructing a new gas-fired combined-cycle turbine at the Big
14 Stone site, abandoning the existing equipment at the Plant; and
- 15 3) Combining a new gas combined-cycle turbine at the Big Stone site
16 with wind generation.

17 Due to the timing of the compliance requirement for operation of the AQCS under the SD Haze
18 SIP, it is unlikely that any of these three natural gas scenarios could be engineered, designed,
19 permitted, procured, and constructed in the same timeframe as the Big Stone AQCS Project.
20 Consequently, there would like be a minimum period of one to three additional years between
21 the retirement of the current Big Stone Plant and the availability of these new resources, during
22 which time OTP, NorthWestern Energy and Montana-Dakota would be dependent on the market
23 or contracted purchases to meet the needs of their customers for the three million MWh per year
24 currently provided by Big Stone. Assessment of the natural gas scenarios are provided below.

25 Other repowering scenarios were considered and ultimately rejected as infeasible, including one
26 scenario involving repowering the existing generating unit with biomass. Biomass fuel may be
27 capable of co-firing up to 10% of the heat input of the Plant, but this would not remove the
28 AQCS Project requirement if coal still comprised 90% of the fuel mix. Achieving a 10% level of
29 biomass as fuel would require drawing on most of the available biomass in a 30 to 50-mile
30 radius, with an estimated delivered cost of \$8 to \$9 per million Btus. This is approximately four
31 times higher than the cost of coal and approximately twice that of natural gas. The conversion to
32 biomass fuel is not a viable response scenario because the AQCS Project would still be required,
33 as well as the cost and logistical challenges involved in securing sufficient biomass fuel.⁵¹

⁵⁰ Conservation and load management were not considered as a feasible alternative response scenario to replace this significant existing baseload facility, as conservation and load management are already assumed to be necessary to meet future resource needs.

⁵¹ The most readily available source of biomass in the area is corn stover. This fuel would likely be delivered in large round bales with 20 to 25 bales per semi-load. At the current firing rate, the Big Stone Plant would need to consume close to ten of these large bales every minute due to the low Btu value, high moisture and low density of the fuel. Thus, biomass co-firing is not a viable regulatory response scenario.

1 The Co-Owners also rejected as infeasible a scenario involving the construction of a gas-fired
2 combustion turbine and a heat-recovery boiler at the Big Stone site, and the use of that steam
3 generation to power the existing Plant turbine. To implement this type of conversion,
4 approximately two-thirds of the generation would come from the new gas-fired generation and
5 one-third would come from the existing steam turbine. The existing steam turbine at Big Stone
6 produces 475 megawatts. Using the 1/3 to 2/3 ratio, the generation from the Big Stone Plant
7 would be required to increase from 475 megawatts to 1,425 megawatts. This additional
8 generation would overload available transmission, since there are already over 2,000 megawatts
9 in the queue at the Big Stone site for additional transmission, and thus could not be available
10 before the AQCS Project's compliance deadline. In addition, this scenario would generate
11 roughly 1,000 megawatts of additional intermediate load generation that is unlikely to fit the
12 needs of the current Big Stone Co-Owners. Due to the time delay, the mismatch of resources
13 and the high cost for such a sizeable gas plant, this response scenario was not further evaluated.

14 **2. Comparative Analysis of the Financial Impacts of Proposed AQCS**
15 **Project and Alternative Regulatory Response Scenarios**

16 To assess financial impacts, the Co-Owners retained the engineering firm of Burns & McDonnell
17 to perform a pro forma economic analysis to calculate the levelized costs of power for the AQCS
18 Project and the alternative response scenarios.⁵²

19 To simplify the analysis, Burns & McDonnell assumed that all response scenarios would be
20 available by January 1, 2016. This assumption favors the alternative scenarios because the Burns
21 & McDonnell analysis does not include any allowance to cover the need to purchase energy from
22 the market during the period, very likely to run at least one to three years (2016 to 2018),
23 between the retirement of Big Stone and the commercial operation of the natural gas scenarios.⁵³

24 To perform its analysis, Burns & McDonnell, as much as possible, used the same modeling
25 inputs as provided by OTP in its most recently filed Minnesota Integrated Resource Plan ("IRP")
26 in Minnesota Docket No. E017/RP-10-623. Courtesy copies were filed with the North Dakota
27 Public Service Commission in late June of 2010. When the necessary inputs for this ADP
28 analysis were not available in the IRP filing, Burns & McDonnell's assumptions were based
29 upon either the analyses prepared by Sargent & Lundy for OTP or the recent project experience
30 of Burns & McDonnell, including its work on projects involving more than 25 gigawatts of gas-
31 fired generation in the last ten years.⁵⁴ Montana-Dakota reviewed the assumptions provided by
32 OTP and agrees that the Burns & McDonnell analyses reasonably represent alternatives available
33 to Montana-Dakota.

⁵² The Burns & McDonnell analysis is provided in Attachment 9.

⁵³ OTP has estimated that the likely cost to enter into a Power Purchase Agreement ("PPA") to meet customer needs during the lag period would be between \$87 million and \$262 million. This estimate assumed the lowest cost option would be a coal PPA.

⁵⁴ The Sargent & Lundy analyses are provided in Attachments 5, 6, and 8.

1 Burns & McDonnell’s analysis covers a 20-year period of operation (which provides a
2 reasonable time period for cost recovery and is within the useful life of the equipment being
3 added and the existing plant) and levelizes construction and operation (including fuel) costs into
4 a levelized cost per Megawatt Hour (MWh). In addition to considering a Base Case analysis,
5 Burns & McDonnell also calculated energy costs if stranded asset costs were included in the
6 repowering and retirement/replacement scenarios and if additional costs for environmental
7 controls for mercury and coal ash were included in the AQCS scenario.

8 a. Base Case Analysis

9 As provided in Joint Exhibit 2, Burns & McDonnell analysis found the AQCS Project the most
10 economical scenario by a substantial margin.⁵⁵ Under the Base Case scenario, the AQCS Project
11 is the lowest cost option by ~~35~~41% over the next lowest cost option, the combined cycle plus
12 wind. Adding the stranded asset cost to the combined cycle plus wind option increases this
13 differential in the cost of energy between these two options to ~~40~~47%, while adding the high
14 environmental costs to the AQCS reduces the cost differential to ~~29~~35%.⁵⁶

15 Table 2 below (also presented in Joint Exhibit 2) provides the results of the Burns & McDonnell
16 analysis. The estimated cost for each scenario in the Base Case analysis is provided in the
17 horizontal row identified as “Combined Levelized Energy Cost.” The estimated levelized energy
18 costs if stranded asset costs are included for the repowering and retirement/replacement scenarios
19 is provided in the horizontal row “Stranded Asset Cost Scenario.” And, the estimated levelized
20 energy costs if additional costs for environmental controls for mercury and coal ash disposal are
21 included in the AQCS option is provided in the row marked as “High Environmental Cost
22 Scenario.”⁵⁷

23

⁵⁵ Attachment 9 at 6-12.

⁵⁶ Attachment 9 at 6-7.

⁵⁷ Under the High Environmental Cost Scenario, Burns & McDonnell assumed an additional \$5 million in capital cost and \$2 million in O & M cost for mercury emission control and an additional \$6.66 million for handling coal ash if it is characterized as a special waste under the RCRA hazardous waste rules. Attachment 9 at 6.

1 **Table 2 – Estimated Levelized Energy Cost (2016\$/MWh)⁵⁸**

	Big Stone + AQCS	CCGT + Wind	CCGT	Big Stone with Natural Gas
Combined Levelized Energy Cost – (Base Case)	\$74.38 <u>70.89</u>	\$100.43	\$103.38	\$117.25
Total Energy Cost Including Stranded Asset Cost	\$74.38 <u>70.89</u>	\$104.24	\$107.19	\$117.25
Total Energy Cost Including High Environmental Costs	\$78.04 <u>74.56</u>	\$100.43	\$103.38	\$117.25

2 b. Sensitivity Analyses

3 In addition to the Base Case analysis, Burns & McDonnell prepared three sensitivity analyses to
 4 assess the effects of capital cost variations, fuel cost variations and operational cost variations.

5 (1) Capital Cost Sensitivity Analysis

6 In this analysis, Burns & McDonnell ran a sensitivity case to consider the effect of a range of
 7 capital costs (plus or minus 30%). In all cases, the AQCS Project was the low cost scenario and
 8 by a substantial margin. For the low end of the range for capital costs (minus 30%), levelized
 9 costs of energy for the AQCS Project were estimated to be ~~\$66.24~~ 64.07 MWh compared to
 10 ~~\$90.09~~ 93.74 MWh for the next least cost scenario (combined cycle and wind). For the high end
 11 of the range for capital costs (plus 30%), the levelized energy cost for the AQCS Project was
 12 ~~\$82.51~~ 77.72 MWh compared to ~~\$106.63~~ 107.12 MWh for the next lowest cost option (combined
 13 cycle wind).⁵⁹

14 (2) Fuel Cost Sensitivity Analysis

15 In this analysis, Burns & McDonnell ran a sensitivity analysis to determine the impact of
 16 changes to the fuel costs for each option. The analysis considered the effect of a range of fuel
 17 costs (plus or minus 20%). Over the range of fuel costs evaluated, the AQCS Project was
 18 preferred in all instances. For the low end of the range of fuel costs (minus 20%), levelized costs
 19 of energy for the AQCS Project were estimated to be ~~\$66.24~~ 63.45 MWh compared to \$90.09
 20 MWh for the next least cost scenario (combined cycle). For the high end of the range for capital
 21 costs (plus 20%), the levelized energy cost for the AQCS Project was ~~\$82.51~~ 78.34 MWh
 22 compared to \$106.63 MWh for the next lowest cost option (combined cycle wind).⁶⁰

23 (3) O & M Sensitivity Analysis

⁵⁸ Attachment 9 at 6, Table 2.

⁵⁹ Attachment 9 at 8, Figure 1.

⁶⁰ Attachment 9 at 9, Figure 2.

1 A sensitivity analysis was performed to determine the impact of changes in O & M costs (plus or
2 minus 20%). The AQCS Project was the preferred option over the range of costs evaluated. In
3 all cases, the AQCS Project was the low cost scenario and by a substantial margin. For the low
4 end of the range for O & M costs (minus 20%), levelized costs of energy for the AQCS Project
5 were estimated to be ~~\$72.21~~68.73 MWh compared to \$99.47 MWh for the next least cost
6 scenario (combined cycle and wind). For the high end of the range for capital costs (plus 20%),
7 the levelized energy cost for the AQCS Project was ~~\$76.54~~73.06 MWh compared to \$101.38
8 MWh for the next lowest cost option (combined cycle wind).⁶¹

9 **3. Comparative Analysis of the Operational Impacts of Proposed AQCS**
10 **Project and Alternative Regulatory Response Scenarios**

11 The financial analysis makes a comparison between the Big Stone AQCS Project and other
12 regulatory response scenarios based on having response scenarios fully capable of replacing the
13 capacity, energy output and dispatchable qualities provided by the Big Stone Plant. There are,
14 however, additional operational differences that are likely to occur between the Big Stone AQCS
15 and implementation of any of the natural gas-based regulatory response scenarios.

16 a. Operational Issues for All Natural Gas Response Scenarios

17 All three natural gas scenarios will impose significantly higher costs per MWh of electricity
18 produced than would the AQCS Project. This in turn means that while the natural gas response
19 scenarios are *capable* of replacing the Big Stone Plant's capacity and energy output, they are
20 likely to be run at significantly lower capacity factors, requiring more frequent access to the
21 market for energy purchases. As a result, significant amounts of power would be purchased at
22 prices lower than the natural gas scenarios, but considerably higher than the energy cost of Big
23 Stone after installation of the AQCS.

24 For example, an energy purchase of \$95/MWh in the Base Case analysis would be economical
25 compared to the natural gas scenarios, but would be \$22/MWh more expensive than power that
26 could be produced by Big Stone with the AQCS Project. To the extent that market price at any
27 given time does not support the operation of natural gas plants, this power is likely to be
28 produced through other means, including by coal-fired power plants.⁶² And in situations where
29 less power is available on the market, the natural gas scenarios would need to be employed, at
30 substantial additional cost to the utilities' customers.

31 The market price/operating cost dynamics that will lower the capacity factors for the natural gas
32 response scenarios also reduce their usefulness for load following wind resources. A high

⁶¹ Attachment 9 at 10, Figure 3.

⁶² The AQCS Project will significantly reduce SO₂ and NO_x emissions from the Plant, while maintaining current high control of particulate matter. In addition, mercury control is planned to target a 90% emission reduction, implemented at the same time as the AQCS. In general, the natural gas options are expected to require installation of NO_x control, but have little emissions of the other pollutants. The extent to which natural gas scenarios would result in less emissions of these pollutants would depend on what the source is for power purchased on the market to fill in for the expected lower capacity factor of the natural gas scenarios.

1 capacity factor baseload resource such as the current Big Stone Plant (and the Big Stone Plant
2 with AQCS) is running many more hours of the year (for example, 85% of the time compared to
3 50% or less of the time), allowing its power output to be increased and decreased quickly in a
4 load following function without the need for a full start up or shut down of the unit.

5 Deploying any of the natural gas scenarios thus includes dramatically increasing the exposure of
6 the utilities' customers to the market price of power and to fluctuations in the price of natural
7 gas, while reducing the load following capability of the Plant. The next sections assess
8 operational impacts that are individual to each regulatory response scenario.

9 b. Repowering the Big Stone Plant with Natural Gas

10 Repowering the Big Stone Plant's boiler to burn natural gas is the highest cost option in the Base
11 Case and among the various sensitivity analyses. Repowering would be less efficient than a new
12 CCGT, which is illustrated by the substantially higher fuel cost in the Base Case (\$99.70/MWh),
13 compared with the other natural gas response scenarios (\$66.44/MWh). The high operating cost
14 of the repowered unit would likely result in limited use of the Plant.⁶³ As a result, the
15 repowering scenario would expose customers to both additional market purchases and more
16 expensive market purchases than the other natural gas scenarios.

17 A repowered unit would take approximately two days to start up and shut down, considerably
18 longer than a new CCGT. High market prices would therefore need to be predicted for a long
19 period of time to justify start up of a repowered unit. In addition, this start up time, combined
20 with a limited use profile, would make a repowered unit unable to effectively load follow wind
21 energy resources on the utilities' electric systems.

22 c. Retirement and Replacement with Natural Gas Combined Cycle
23 Plant

24 Replacement of the Big Stone Plant with a new natural gas combined cycle unit at the Big Stone
25 site was evaluated in two scenarios: CCGT and CCGT/Wind Power Purchases. Both scenarios
26 are significantly higher cost in the Base Case, as well as in all sensitivity analyses.

27 Operationally, the CCGT scenario would allow a faster start up and shut down time than the
28 repowering scenario. CCGTs would start up or shut down in 3-5 hours, substantially slower than
29 a peaking unit such as a Simple Cycle Gas Turbine, which can start up in 10 minutes.⁶⁴ Due to
30 its cost of power per MWh, however, a CCGT would likely have an intermediate, rather than a
31 baseload, capacity factor of about 30 to 50%. This would make it less desirable for load
32 following because it would have many more hours during the year when it is not operating at all.
33 Load following would therefore require more start ups and shut downs than for a baseload plant,

⁶³ The repowered unit would be expected to have the highest cost per MWh, despite its relatively lower capital cost (\$267 million) than the other natural gas response scenarios (\$621.29 million), because its lower efficiency increases its fuel cost per MWh of power produced. See Attachment 9 at 6, Table 2.

⁶⁴ A Simple Cycle Gas Turbine ("SCGT") is not a viable alternative response scenario, because it cannot replace the Big Stone Plant as a baseload resource.

1 increasing the O & M costs for the unit. When a CCGT unit is running, however, it would be
2 capable of increasing or decreasing its output to follow load.

3 The CCGT and CCGT/Wind Power Purchases scenarios have similar costs per MWh through the
4 different sensitivity analyses, with the CCGT slightly more expensive except in the case of a
5 drop in the price of natural gas of 10% or more. The capital cost of the CCGT scenarios,
6 \$621,289,115 (2016\$), is about 27% higher than the capital cost of the Big Stone AQCS Project.

7 **C. CONCLUSION**

8 The financial analysis demonstrates that the Big Stone AQCS is the most economic scenario in
9 the Base Case, and in the Base Case with an increase for Stranded Asset Costs and for
10 anticipated environmental costs (“High Environmental Cost”). The Base Case analysis
11 comparing installation of the AQCS with various options for repowering or retiring and
12 replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with
13 the cost of the other options ~~35~~41% or more higher than the levelized MWh cost of the proposed
14 AQCS. The AQCS remains the most cost-effective option under several sensitivity analyses
15 concerning capital cost (+/-30%), fuel cost (+/-20%) and O & M cost (+/-20%).

16 Under multiple scenarios that consider potential changes in capital, O & M and fuel costs, the
17 Big Stone AQCS remains the least cost option. This conclusion does not change when
18 considering the potential for additional costs that may be imposed by anticipated environmental
19 regulation. Repowering is the highest cost natural gas scenario, with the worst load following
20 capability. Retirement of the Plant and replacement with a CCGT has a significantly higher
21 capital cost than the Big Stone AQCS.

22 Implementation of any of the natural gas response scenarios instead of the Big Stone AQCS
23 would unreasonably expose North Dakota customers to significantly higher costs under a wide
24 range of potential future conditions. In addition, deploying any of the natural gas scenarios
25 dramatically increases the exposure of North Dakota customers to the market price of power and
26 to fluctuations in the price of natural gas, while reducing the load following capability of the
27 Plant.

28 The assessment of the financial and operational inputs of the anticipated regulations to the Big
29 Stone Plant demonstrates that the proposed AQCS Project is reasonable and prudent.

1 **III. Joint Exhibit 3 - ASSESSMENT OF FINANCIAL AND OPERATIONAL**
2 **IMPACTS OF PENDING ENVIRONMENTAL REGULATIONS TO THE BIG**
3 **STONE PLANT**

4 The Co-Owners provide this assessment of the financial and operational impacts of pending
5 environmental regulations, including the SD Haze SIP, to the Big Stone Plant. The assessment
6 covers the installation of the pollution controls that comprise the proposed AQCS, as well as
7 other regulatory response scenarios that may be reasonable in view of the costs to comply with
8 the SD Haze SIP, including the retirement or repowering of the Big Stone Plant with natural gas.

9 By installing the AQCS, the Co-Owners customers will continue to receive the benefits of low-
10 cost, reliable electric power from an existing baseload resource, without the need for
11 development of either a greenfield site or new transmission. In addition, as a baseload resource
12 that is frequently used for load following, the Big Stone Plant is a critical resource for a system
13 that is becoming more dependent on wind power and other variable resources. As this
14 Assessment shows, the continued operation of the Big Stone Plant with the addition of the AQCS
15 is a cost effective means to the meet the future needs of the Co-Owners' customers when taking
16 into the account the costs required to comply with the SD Haze SIP and other pending
17 environmental regulations and other viable regulatory response scenarios. The cost estimates
18 and analysis provided in this Assessment were prepared by OTP, on behalf of the Co-Owners
19 with assistance from the engineering firms of Sargent & Lundy and Burns & McDonnell.

20 **A. FINANCIAL AND OPERATIONAL IMPACTS OF PROPOSED AQCS**
21 **PROJECT**

22 The SD Haze SIP determined that BART for the Plant is comprised of a separated over fired air
23 system for the Big Stone Plant boiler to reduce the formation of NO_x, an SCR to chemically
24 reduce NO_x into N₂ and H₂O, a Semi-Dry FGD for SO₂ control, and a baghouse for particulate
25 matter control. The AQCS Project would also include all the ductwork, boiler modifications and
26 infrastructure changes needed to support the required equipment. The AQCS Project is
27 necessary to meet the BART requirements of the SD Haze SIP and its implementing regulations.
28 Without installation of the AQCS, the Plant will not be able to comply with the emission
29 limitations that represent BART, and cannot operate after the deadline for BART compliance has
30 passed.³¹

31 **1. Financial Impacts of Proposed AQCS Project**

32 The estimated capital cost for acquisition and installation of the equipment and support systems
33 for the AQCS is approximately \$489 million (2015 dollars).³² This estimate provides an
34 accuracy range of +/- 20% and is the total project cost escalated to its commercial operation date,
35 which is expected to be late in 2015. Montana-Dakota's North Dakota customers will see an
36 approximate 16 percent increase in rates as a result of its share of this total project cost of \$78

³¹ See ADP Application, Joint Exhibit 1, Section B, Requirement to Implement the Big Stone AQCS Project.

³² See Attachment 5 & ADP Application, Joint Exhibit 1, Section E, Cost Estimate.

1 million. OTP's North Dakota customers will also see an approximate 16 percent increase in
2 rates as a result of its share of this total project cost of \$108 million.

3 The estimated additional increase in the Plant's operation cost in 2016, the expected first full
4 year of operation, associated with the operation of the AQCS, will be approximately \$11 million
5 (including escalation from 2010 dollars).³³ The additional operating expense will increase the
6 cost to produce a MWh of energy by approximately \$3.50, or \$.0035 per kWh, based on the
7 Plant's net dispatchable energy generation of 3,120,750 MWh. After the AQCS is installed and
8 in operation, the estimated total operating cost for the Plant in 2016 is \$27.3 million,³⁴ with
9 Montana-Dakota's North Dakota share being approximately \$4.0 million and OTP's share of
10 approximately \$6.0 million. The biggest operational cost increase will be due to the cost of the
11 lime and ammonia necessary to operate the SCR and semi-dry FGD and the addition of
12 employees at the Plant.³⁵

13 Beyond the additional cost to install and operate the AQCS, additional capital and operating
14 costs are likely to be required in response to anticipated regulations for control of mercury
15 emissions and disposal of coal combustion residual (coal ash).³⁶ The addition of control for
16 mercury, which is likely to be required during the same timeframe as the AQCS Project, is
17 estimated to result in additional capital cost of approximately \$5 million³⁷ and an additional
18 operating cost of approximately \$2 million per year.³⁸ The estimated cost to comply with
19 regulations relating to mercury control will add approximately \$0.65 to the cost to produce a
20 MWh of energy, or \$.00065 per kWh.

21 Table 1 contains a summary of the potential anticipated financial impacts of the proposed AQCS,
22 mercury emission standard, and the potential cost of coal ash regulation.

23

33 Attachment 6.

34 Attachment 6.

35 Attachment 4, Section 6.

36 In addition to the requirements for the AQCS, the Assessment of Financial and Operational Impacts of Pending Environmental Regulations to the Big Stone Plant considered potential cost of new environmental regulations applicable to the Big Stone Plant relating to mercury emission limits and coal ash disposal.

37 Attachment 5, ACI Estimate.

38 Attachment 6.

1

Table 1 – Anticipated Financial Impacts

	Capital Cost (2015\$)	Annual O & M Cost (2016\$)	Levelized Cost (2016\$/MWh)
Big Stone + AQCS	\$489 million ³⁹	\$27.3 million ⁴⁰	\$70.89 ⁴¹
Mercury Control and Coal Ash Disposal ⁴²	\$5 million	\$8.7 million	\$3.66 ⁴³

2

3

4

2. Operational Impacts of Proposed AQCS Project

5 Apart from capital and increased operating costs, the installation of the AQCS will not have any
 6 significant impacts on the capacity or day-to-day operations of the Big Stone Plant, except for
 7 one longer than typical outage in 2015 to connect the AQCS into the Plant once the AQCS
 8 systems have been constructed. However, there are certain challenges that are being addressed
 9 in the design of the proposed AQCS Project and that have been included in the cost estimates for
 10 the AQCS.

11 First, some modifications need to be made to the boiler to allow for effective operation of the
 12 SCR. The SCR provides effective control of NO_x emissions, but it operates well only within a
 13 specified temperature range.⁴⁴ The boiler temperatures must be maintained so they are neither
 14 too hot at full load nor too cold at low loads. To ensure that proper temperatures are maintained,
 15 the Plant's boiler will need to be modified.⁴⁵ The boiler efficiency is expected to improve as a
 16 result of the modifications, and the hourly boiler heat input will not increase above the current
 17 permitted levels.

18 The design of the AQCS equipment must also allow the Plant to maintain its current ability to
 19 follow load. Varying load conditions must be taken into account in the design of the semi-dry
 20 FGD and SCR. Currently, the Plant will run in a load following arrangement for much of the

³⁹ Attachment 5.

⁴⁰ Attachment 6.

⁴¹ Attachment 9 at 6, Table 2.

⁴² The addition of mercury control equipment is estimated to cost approximately \$5 million, Attachment 5, ACI Estimate, and the annual O & M cost for the mercury control equipment is estimated to be \$2 million, Attachment 6. The increased costs for disposal of coal ash could be as high as approximately \$6.7 million per year, based on a \$37.50 per ton estimate for disposal, including both capital and operating costs. Section IV; *Special Reliability Assessment: Resource Adequacy Impact of Potential U.S. Environmental Regulations*, at 57, NERC (October 2010).

⁴³ Attachment 9 at 5-6.

⁴⁴ Attachment 4 at 3-4.

⁴⁵ Attachment 4, Section 3.2, describes boiler modifications that are anticipated to be needed as a result of the AQCS Project.

1 spring and fall. For example, on a typical spring day when the demand for electricity is
2 relatively low, the Plant is likely to see minimum load at night, but as the electrical load starts
3 increasing, the output of the Plant will rise until it reaches full load during the peak load periods,
4 and then drop off as the electric load drops off at night, eventually getting back to the minimum
5 load for a few hours before repeating the cycle. The design of the AQCS equipment will assure
6 that the ability of the Plant to follow load is not compromised and that the AQCS Project does
7 not decrease the range of load at which the unit may efficiently and safely operate. For example,
8 the AQCS Project will be designed to minimize the duct distance between the semi-dry FGD and
9 the baghouse to limit the amount of ash depositing in the duct work at low loads. Other design
10 considerations involve ensuring that proper temperatures are maintained and that equipment is
11 the appropriate size to operate at both low and full loads.⁴⁶

12 Other operational impacts of the AQCS Project will include the addition of employees to operate
13 and maintain the Plant with the additional equipment.⁴⁷ OTP will provide training on operation
14 of the new equipment to the new employees. Additionally, operation of Big Stone following
15 installation of the AQCS will produce a greater volume of ash to be disposed of because the
16 addition of the semi-dry FGD will result in ash that is less dense than the ash currently produced
17 by the Plant. OTP has sufficient capacity in its existing disposal site for this ash.⁴⁸

18 **B. ALTERNATIVE RESPONSE SCENARIOS**

19 **1. Selection of Alternative Response Scenarios**

20 OTP, on behalf of the Co-Owners has focused on the identification of alternative scenarios that
21 involve either the retirement and replacement or the repowering of the Big Stone Plant. In view
22 of the specific requirements set out in the SD Haze SIP and its implementing regulations, there is
23 only one response scenario that involves the installation of pollution control equipment and that
24 scenario is the proposed AQCS Project. In addition, the use of pollution allowances is not a
25 viable compliance approach because there are no pollution trading programs available that can
26 substitute for BART compliance and address the underlying regulatory concern for visibility in
27 Class I areas.⁴⁹

28 OTP, on behalf of the Co-Owners, assessed the current status of Greenhouse Gas Regulatory
29 requirements when considering alternatives. Congress has considered, but has not adopted,
30 legislation which would require a reduction in Greenhouse Gas (GHG) emissions. However,

⁴⁶ Attachment 4 at 2-5.

⁴⁷ Attachment 4 at 6-1.

⁴⁸ *Id.* at 3-22.

⁴⁹ Emission trading of SO₂ and NO_x may have limited potential to be an option for plants located in the Transport Rule's control zone, subject to affected state decisions in their regional haze SIPs, but South Dakota is not a state proposed for inclusion under that rule. Emission trading of SO₂ under the Acid Deposition Program is in addition to, and does not affect the requirement to comply with other CAA program requirements, such as the regional haze program. 42 U.S.C. § 7651b(f) (CAA § 403(f)).

1 there is no legislation under active consideration at this time. The EPA is proceeding to regulate
2 GHGs under a number of provisions of the Clean Air Act beginning with regulation under the
3 Prevention of Significant Deterioration (PSD) and the Title V permitting process in January
4 2011. OTP does not anticipate making modifications at Big Stone as part of the AQCS project
5 that would trigger PSD requirements, including for GHGs. Consequently, GHG emissions are
6 not projected to trigger the need for a PSD permit as a result of the AQCS Project.

7
8 EPA has announced a timeframe for developing New Source Performance Standards (NSPS) for
9 GHGs from electric generating units. EPA plans to propose this NSPS in August 2011, and
10 adopt the standard in June 2012. In general, NSPS become applicable to new sources built after
11 the effective date of the regulation, or affect what may be required to be included as an emission
12 control at the time an existing source makes a change significant enough to trigger NSPS
13 applicability. To trigger the applicability of NSPS, an existing source must make a modification
14 that increases its maximum hourly emissions rate. The Co-Owners do not anticipate making a
15 modification at Big Stone Plant that would trigger NSPS requirements. The Big Stone AQCS
16 Project is not projected to trigger the applicability of the NSPS for GHGs that EPA plans to
17 develop.

18
19 At the same time EPA develops the NSPS, EPA also plans to issue emission guidelines for
20 existing sources under CAA Section 111(d) (111(d) Standard). A 111(d) Standard, unlike the
21 NSPS, applies to an existing source. States are given a period of time to develop plans to
22 implement a 111(d) Standard, and if a state does not develop such a plan, EPA will prescribe a
23 plan for that state.

24
25 While the potential impact of a 111(d) standard on Big Stone is not yet known, standards of
26 performance for GHGs, especially for existing sources, are anticipated to focus on efficiency
27 improvements rather than add-on controls. The Co-Owners have in the past implemented
28 efficiency measures at Big Stone through installation of a more efficient steam turbine at the
29 Plant. The capital cost of efficiency improvements could be offset in whole or in part by reduced
30 fuel costs.

31
32 To identify potentially viable alternatives for economic evaluation, OTP, on behalf of the Co-
33 Owners first identified the needs currently served by the Big Stone Plant, as well as the basic
34 operating characteristics of the Plant. The Big Stone Plant is a key baseload asset for its three
35 utility Co-Owners, serving the existing load of customers in several states. The Plant is the
36 largest baseload resource for each of the Co-Owners. Given the critical resource role played by
37 the Big Stone Plant, OTP, on behalf of the Co-Owners developed alternatives that were capable
38 of reliably: (1) producing approximately 3 million megawatt-hours of electricity per year;
39 (2) serving as a baseload resource, with the ability to follow load and be a dispatchable resource
40 with high availability; and (3) being in operation prior to expiration of the deadline for Big Stone
41 to comply with the BART requirement. Analysis performed by the Midwest Independent
42 Transmission System Operator ("MISO") has assumed the presence of a baseload generation
43 source at the Big Stone site, and any change in location would require a reevaluation of the
44 transmission system.

45 Given the significant customer load served by the Big Stone Plant, the Co-Owners identified
46 coal, hydropower, nuclear and natural gas as practical potential replacement options that could

1 meet the above criteria.⁵⁰ Since the proposed AQCS Project includes continuation of coal
2 generation at the Plant, another coal option was not considered as an alternative response
3 scenario. Hydropower and new nuclear generation were rejected because expected permitting
4 difficulties suggest that these resources could not be available in the timeframe required for
5 compliance with the SD Haze SIP and its implementing rules and because the size of these
6 alternatives to be economic, would exceed the needs of the Co-Owners. Based on these
7 considerations, it was determined that natural gas was the only viable retirement/replacement or
8 repowering option that could potentially replace the current functions of the Big Stone Plant in
9 the required timeframe.

10 With respect to natural gas, three different scenarios were assessed:

- 11 1) Converting the existing Big Stone boiler to natural gas
12 combustion;
- 13 2) Constructing a new gas-fired combined-cycle turbine at the Big
14 Stone site, abandoning the existing equipment at the Plant; and
- 15 3) Combining a new gas combined-cycle turbine at the Big Stone site
16 with wind generation.

17 Due to the timing of the compliance requirement for operation of the AQCS under the SD Haze
18 SIP, it is unlikely that any of these three natural gas scenarios could be engineered, designed,
19 permitted, procured, and constructed in the same timeframe as the Big Stone AQCS Project.
20 Consequently, there would like be a minimum period of one to three additional years between
21 the retirement of the current Big Stone Plant and the availability of these new resources, during
22 which time OTP, NorthWestern Energy and Montana-Dakota would be dependent on the market
23 or contracted purchases to meet the needs of their customers for the three million MWh per year
24 currently provided by Big Stone. Assessment of the natural gas scenarios are provided below.

25 Other repowering scenarios were considered and ultimately rejected as infeasible, including one
26 scenario involving repowering the existing generating unit with biomass. Biomass fuel may be
27 capable of co-firing up to 10% of the heat input of the Plant, but this would not remove the
28 AQCS Project requirement if coal still comprised 90% of the fuel mix. Achieving a 10% level of
29 biomass as fuel would require drawing on most of the available biomass in a 30 to 50-mile
30 radius, with an estimated delivered cost of \$8 to \$9 per million Btus. This is approximately four
31 times higher than the cost of coal and approximately twice that of natural gas. The conversion to
32 biomass fuel is not a viable response scenario because the AQCS Project would still be required,
33 as well as the cost and logistical challenges involved in securing sufficient biomass fuel.⁵¹

⁵⁰ Conservation and load management were not considered as a feasible alternative response scenario to replace this significant existing baseload facility, as conservation and load management are already assumed to be necessary to meet future resource needs.

⁵¹ The most readily available source of biomass in the area is corn stover. This fuel would likely be delivered in large round bales with 20 to 25 bales per semi-load. At the current firing rate, the Big Stone Plant would need to consume close to ten of these large bales every minute due to the low Btu value, high moisture and low density of the fuel. Thus, biomass co-firing is not a viable regulatory response scenario.

1 The Co-Owners also rejected as infeasible a scenario involving the construction of a gas-fired
2 combustion turbine and a heat-recovery boiler at the Big Stone site, and the use of that steam
3 generation to power the existing Plant turbine. To implement this type of conversion,
4 approximately two-thirds of the generation would come from the new gas-fired generation and
5 one-third would come from the existing steam turbine. The existing steam turbine at Big Stone
6 produces 475 megawatts. Using the 1/3 to 2/3 ratio, the generation from the Big Stone Plant
7 would be required to increase from 475 megawatts to 1,425 megawatts. This additional
8 generation would overload available transmission, since there are already over 2,000 megawatts
9 in the queue at the Big Stone site for additional transmission, and thus could not be available
10 before the AQCS Project's compliance deadline. In addition, this scenario would generate
11 roughly 1,000 megawatts of additional intermediate load generation that is unlikely to fit the
12 needs of the current Big Stone Co-Owners. Due to the time delay, the mismatch of resources
13 and the high cost for such a sizeable gas plant, this response scenario was not further evaluated.

14 **2. Comparative Analysis of the Financial Impacts of Proposed AQCS**
15 **Project and Alternative Regulatory Response Scenarios**

16 To assess financial impacts, the Co-Owners retained the engineering firm of Burns & McDonnell
17 to perform a pro forma economic analysis to calculate the levelized costs of power for the AQCS
18 Project and the alternative response scenarios.⁵²

19 To simplify the analysis, Burns & McDonnell assumed that all response scenarios would be
20 available by January 1, 2016. This assumption favors the alternative scenarios because the Burns
21 & McDonnell analysis does not include any allowance to cover the need to purchase energy from
22 the market during the period, very likely to run at least one to three years (2016 to 2018),
23 between the retirement of Big Stone and the commercial operation of the natural gas scenarios.⁵³

24 To perform its analysis, Burns & McDonnell, as much as possible, used the same modeling
25 inputs as provided by OTP in its most recently filed Minnesota Integrated Resource Plan ("IRP")
26 in Minnesota Docket No. E017/RP-10-623. Courtesy copies were filed with the North Dakota
27 Public Service Commission in late June of 2010. When the necessary inputs for this ADP
28 analysis were not available in the IRP filing, Burns & McDonnell's assumptions were based
29 upon either the analyses prepared by Sargent & Lundy for OTP or the recent project experience
30 of Burns & McDonnell, including its work on projects involving more than 25 gigawatts of gas-
31 fired generation in the last ten years.⁵⁴ Montana-Dakota reviewed the assumptions provided by
32 OTP and agrees that the Burns & McDonnell analyses reasonably represent alternatives available
33 to Montana-Dakota.

⁵² The Burns & McDonnell analysis is provided in Attachment 9.

⁵³ OTP has estimated that the likely cost to enter into a Power Purchase Agreement ("PPA") to meet customer needs during the lag period would be between \$87 million and \$262 million. This estimate assumed the lowest cost option would be a coal PPA.

⁵⁴ The Sargent & Lundy analyses are provided in Attachments 5, 6, and 8.

1 Burns & McDonnell’s analysis covers a 20-year period of operation (which provides a
2 reasonable time period for cost recovery and is within the useful life of the equipment being
3 added and the existing plant) and levelizes construction and operation (including fuel) costs into
4 a levelized cost per Megawatt Hour (MWh). In addition to considering a Base Case analysis,
5 Burns & McDonnell also calculated energy costs if stranded asset costs were included in the
6 repowering and retirement/replacement scenarios and if additional costs for environmental
7 controls for mercury and coal ash were included in the AQCS scenario.

8 a. Base Case Analysis

9 As provided in Joint Exhibit 2, Burns & McDonnell analysis found the AQCS Project the most
10 economical scenario by a substantial margin.⁵⁵ Under the Base Case scenario, the AQCS Project
11 is the lowest cost option by 41% over the next lowest cost option, the combined cycle plus wind.
12 Adding the stranded asset cost to the combined cycle plus wind option increases this differential
13 in the cost of energy between these two options to 47%, while adding the high environmental
14 costs to the AQCS reduces the cost differential to 35%.⁵⁶

15 Table 2 below (also presented in Joint Exhibit 2) provides the results of the Burns & McDonnell
16 analysis. The estimated cost for each scenario in the Base Case analysis is provided in the
17 horizontal row identified as “Combined Levelized Energy Cost.” The estimated levelized energy
18 costs if stranded asset costs are included for the repowering and retirement/replacement scenarios
19 is provided in the horizontal row “Stranded Asset Cost Scenario.” And, the estimated levelized
20 energy costs if additional costs for environmental controls for mercury and coal ash disposal are
21 included in the AQCS option is provided in the row marked as “High Environmental Cost
22 Scenario.”⁵⁷

23

⁵⁵ Attachment 9 at 6-12.

⁵⁶ Attachment 9 at 6-7.

⁵⁷ Under the High Environmental Cost Scenario, Burns & McDonnell assumed an additional \$5 million in capital cost and \$2 million in O & M cost for mercury emission control and an additional \$6.66 million for handling coal ash if it is characterized as a special waste under the RCRA hazardous waste rules. Attachment 9 at 6.

1 **Table 2 – Estimated Levelized Energy Cost (2016\$/MWh)⁵⁸**

	Big Stone + AQCS	CCGT + Wind	CCGT	Big Stone with Natural Gas
Combined Levelized Energy Cost – (Base Case)	\$70.89	\$100.43	\$103.38	\$117.25
Total Energy Cost Including Stranded Asset Cost	\$70.89	\$104.24	\$107.19	\$117.25
Total Energy Cost Including High Environmental Costs	\$74.56	\$100.43	\$103.38	\$117.25

2 b. Sensitivity Analyses

3 In addition to the Base Case analysis, Burns & McDonnell prepared three sensitivity analyses to
4 assess the effects of capital cost variations, fuel cost variations and operational cost variations.

5 (1) Capital Cost Sensitivity Analysis

6 In this analysis, Burns & McDonnell ran a sensitivity case to consider the effect of a range of
7 capital costs (plus or minus 30%). In all cases, the AQCS Project was the low cost scenario and
8 by a substantial margin. For the low end of the range for capital costs (minus 30%), levelized
9 costs of energy for the AQCS Project were estimated to be \$64.07 MWh compared to \$93.74
10 MWh for the next least cost scenario (combined cycle and wind). For the high end of the range
11 for capital costs (plus 30%), the levelized energy cost for the AQCS Project was \$77.72 MWh
12 compared to \$107.12 MWh for the next lowest cost option (combined cycle wind).⁵⁹

13 (2) Fuel Cost Sensitivity Analysis

14 In this analysis, Burns & McDonnell ran a sensitivity analysis to determine the impact of
15 changes to the fuel costs for each option. The analysis considered the effect of a range of fuel
16 costs (plus or minus 20%). Over the range of fuel costs evaluated, the AQCS Project was
17 preferred in all instances. For the low end of the range of fuel costs (minus 20%), levelized costs
18 of energy for the AQCS Project were estimated to be \$63.45 MWh compared to \$90.09 MWh for
19 the next least cost scenario (combined cycle). For the high end of the range for capital costs
20 (plus 20%), the levelized energy cost for the AQCS Project was \$78.34 MWh compared to
21 \$106.63 MWh for the next lowest cost option (combined cycle wind).⁶⁰

22 (3) O & M Sensitivity Analysis

23 A sensitivity analysis was performed to determine the impact of changes in O & M costs (plus or
24 minus 20%). The AQCS Project was the preferred option over the range of costs evaluated. In

⁵⁸ Attachment 9 at 6, Table 2.

⁵⁹ Attachment 9 at 8, Figure 1.

⁶⁰ Attachment 9 at 9, Figure 2.

1 all cases, the AQCS Project was the low cost scenario and by a substantial margin. For the low
2 end of the range for O & M costs (minus 20%), levelized costs of energy for the AQCS Project
3 were estimated to be \$68.73 MWh compared to \$99.47 MWh for the next least cost scenario
4 (combined cycle and wind). For the high end of the range for capital costs (plus 20%), the
5 levelized energy cost for the AQCS Project was \$73.06 MWh compared to \$101.38 MWh for the
6 next lowest cost option (combined cycle wind).⁶¹

7 **3. Comparative Analysis of the Operational Impacts of Proposed AQCS**
8 **Project and Alternative Regulatory Response Scenarios**

9 The financial analysis makes a comparison between the Big Stone AQCS Project and other
10 regulatory response scenarios based on having response scenarios fully capable of replacing the
11 capacity, energy output and dispatchable qualities provided by the Big Stone Plant. There are,
12 however, additional operational differences that are likely to occur between the Big Stone AQCS
13 and implementation of any of the natural gas-based regulatory response scenarios.

14 a. Operational Issues for All Natural Gas Response Scenarios

15 All three natural gas scenarios will impose significantly higher costs per MWh of electricity
16 produced than would the AQCS Project. This in turn means that while the natural gas response
17 scenarios are *capable* of replacing the Big Stone Plant's capacity and energy output, they are
18 likely to be run at significantly lower capacity factors, requiring more frequent access to the
19 market for energy purchases. As a result, significant amounts of power would be purchased at
20 prices lower than the natural gas scenarios, but considerably higher than the energy cost of Big
21 Stone after installation of the AQCS.

22 For example, an energy purchase of \$95/MWh in the Base Case analysis would be economical
23 compared to the natural gas scenarios, but would be \$22/MWh more expensive than power that
24 could be produced by Big Stone with the AQCS Project. To the extent that market price at any
25 given time does not support the operation of natural gas plants, this power is likely to be
26 produced through other means, including by coal-fired power plants.⁶² And in situations where
27 less power is available on the market, the natural gas scenarios would need to be employed, at
28 substantial additional cost to the utilities' customers.

29 The market price/operating cost dynamics that will lower the capacity factors for the natural gas
30 response scenarios also reduce their usefulness for load following wind resources. A high
31 capacity factor baseload resource such as the current Big Stone Plant (and the Big Stone Plant
32 with AQCS) is running many more hours of the year (for example, 85% of the time compared to

⁶¹ Attachment 9 at 10, Figure 3.

⁶² The AQCS Project will significantly reduce SO₂ and NO_x emissions from the Plant, while maintaining current high control of particulate matter. In addition, mercury control is planned to target a 90% emission reduction, implemented at the same time as the AQCS. In general, the natural gas options are expected to require installation of NO_x control, but have little emissions of the other pollutants. The extent to which natural gas scenarios would result in less emissions of these pollutants would depend on what the source is for power purchased on the market to fill in for the expected lower capacity factor of the natural gas scenarios.

1 The CCGT and CCGT/Wind Power Purchases scenarios have similar costs per MWh through the
2 different sensitivity analyses, with the CCGT slightly more expensive except in the case of a
3 drop in the price of natural gas of 10% or more. The capital cost of the CCGT scenarios,
4 \$621,289,115 (2016\$), is about 27% higher than the capital cost of the Big Stone AQCS Project.

5 **C. CONCLUSION**

6 The financial analysis demonstrates that the Big Stone AQCS is the most economic scenario in
7 the Base Case, and in the Base Case with an increase for Stranded Asset Costs and for
8 anticipated environmental costs (“High Environmental Cost”). The Base Case analysis
9 comparing installation of the AQCS with various options for repowering or retiring and
10 replacing the Plant with natural gas shows that the AQCS is the most cost-effective option, with
11 the cost of the other options 41% or more higher than the levelized MWh cost of the proposed
12 AQCS. The AQCS remains the most cost-effective option under several sensitivity analyses
13 concerning capital cost (+/-30%), fuel cost (+/-20%) and O & M cost (+/-20%).

14 Under multiple scenarios that consider potential changes in capital, O & M and fuel costs, the
15 Big Stone AQCS remains the least cost option. This conclusion does not change when
16 considering the potential for additional costs that may be imposed by anticipated environmental
17 regulation. Repowering is the highest cost natural gas scenario, with the worst load following
18 capability. Retirement of the Plant and replacement with a CCGT has a significantly higher
19 capital cost than the Big Stone AQCS.

20 Implementation of any of the natural gas response scenarios instead of the Big Stone AQCS
21 would unreasonably expose North Dakota customers to significantly higher costs under a wide
22 range of potential future conditions. In addition, deploying any of the natural gas scenarios
23 dramatically increases the exposure of North Dakota customers to the market price of power and
24 to fluctuations in the price of natural gas, while reducing the load following capability of the
25 Plant.

26 The assessment of the financial and operational inputs of the anticipated regulations to the Big
27 Stone Plant demonstrates that the proposed AQCS Project is reasonable and prudent.