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

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

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

A. FINANCIAL AND OPERATIONAL IMPACTS OF PROPOSED AQCS PROJECT

The SD Haze SIP determined that BART for the Plant is comprised of a separated over fired air system for the Big Stone Plant boiler to reduce the formation of NO_X , an SCR to chemically reduce NO_X into N_2 and H_2O, a Semi-Dry FGD for SO_2 control, and a baghouse for particulate matter control. The AQCS Project would also include all the ductwork, boiler modifications and infrastructure changes needed to support the required equipment. The AQCS Project is necessary to meet the BART requirements of the SD Haze SIP and its implementing regulations. Without installation of the AQCS, the Plant will not be able to comply with the emission limitations that represent BART, and cannot operate after the deadline for BART compliance has passed.[31]

1. Financial Impacts of Proposed AQCS Project

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

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[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.

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

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

Beyond the additional cost to install and operate the AQCS, additional capital and operating costs are likely to be required in response to anticipated regulations for control of mercury emissions and disposal of coal combustion residual (coal ash).[36] The addition of control for mercury, which is likely to be required during the same timeframe as the AQCS Project, is estimated to result in additional capital cost of approximately $5 million[37] and an additional operating cost of approximately $2 million per year.[38] The estimated cost to comply with regulations relating to mercury control will add approximately $0.65 to the cost to produce a MWh of energy, or $.00065 per kWh.

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

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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.

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. Operational Impacts of Proposed AQCS Project

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

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

The design of the AQCS equipment must also allow the Plant to maintain its current ability to follow load. Varying load conditions must be taken into account in the design of the semi-dry 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.

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

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

B. ALTERNATIVE RESPONSE SCENARIOS

1. Selection of Alternative Response Scenarios

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

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

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46 Attachment 4 at 2-5.

47 Attachment 4 at 6-1.

48 *Id.* at 3-22.

49 Emission trading of SO_2 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 SO_2 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)).

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

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

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

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

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

Given the significant customer load served by the Big Stone Plant, the Co-Owners identified coal, hydropower, nuclear and natural gas as practical potential replacement options that could meet the above criteria.[50] Since the proposed AQCS Project includes continuation of coal generation at the Plant, another coal option was not considered as an alternative response scenario. Hydropower and new nuclear generation were rejected because expected permitting difficulties suggest that these resources could not be available in the timeframe required for compliance with the SD Haze SIP and its implementing rules and because the size of these alternatives to be economic, would exceed the needs of the Co-Owners. Based on these considerations, it was determined that natural gas was the only viable retirement/replacement or repowering option that could potentially replace the current functions of the Big Stone Plant in the required timeframe.

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

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

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

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

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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.

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

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

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

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

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

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[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.

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

a. Base Case Analysis

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

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

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.

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

b. <u>Sensitivity Analyses</u>

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

(1) Capital Cost Sensitivity Analysis

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

(2) Fuel Cost Sensitivity Analysis

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

(3) O & M Sensitivity Analysis

A sensitivity analysis was performed to determine the impact of changes in O & M costs (plus or 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.

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

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

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

a. Operational Issues for All Natural Gas Response Scenarios

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

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

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

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61 Attachment 9 at 10, Figure 3.

62 The AQCS Project will significantly reduce SO_2 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.

50% or less of the time), allowing its power output to be increased and decreased quickly in a load following function without the need for a full start up or shut down of the unit.

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

b. Repowering the Big Stone Plant with Natural Gas

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

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

c. Retirement and Replacement with Natural Gas Combined Cycle Plant

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

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

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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.

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

C. CONCLUSION

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

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

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

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