EXHIBITS TO

APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE

TABLE OF CONTENTS

Page

ATTACHMENTS

Attachment 1 -	South Dakota Regional Haze State Implementation Plan, Section 6.0, Best Available Retrofit Technology
Attachment 2 -	Assessment of Anticipated Federal and State Environmental Regulations
Attachment 3 -	Administrative Rules of South Dakota Chapter 74:36:21
Attachment 4 -	SO_2, NO_x, and Mercury Reduction Study
Attachment 5 -	Big Stone Plant AQCS Project Cost Estimate
Attachment 6 -	Big Stone AQCS Project Operating and Maintenance Cost Calculations
Attachment 7 -	Contract Strategy Summary
Attachment 8 -	Natural Gas Conversion Conceptual Study
Attachment 9 -	Otter Tail Power Company BSP Pro Forma Results Letter Report North Dakota

I. Joint Exhibit 1 - THE BIG STONE AIR QUALITY CONTROL SYSTEM PROJECT

A. Big Stone Plant Description

The Big Stone Plant ("Big Stone" or "Plant") is located in Grant County, South Dakota, 2.5 miles northwest of Big Stone City, South Dakota, which is near the Minnesota/South Dakota border. Big Stone is rated at 495 MW gross and 475 MW net electrical output. The Plant has three owners; Otter Tail Power Company ("OTP") owns 53.9 percent of the Plant, NorthWestern Energy owns 23.4 percent, and Montana-Dakota Utilities Co. ("Montana-Dakota") owns 22.7 percent. The Co-Owners, as investor owned utilities, use the Plant to provide electricity to customers in their South Dakota, North Dakota, Montana and Minnesota service areas. Montana-Dakota and OTP serve North Dakota load. The Plant was built in the early 1970s and began commercial operation on May 1, 1975. Montana-Dakota and OTP request in their Applications that the Commission find prudent Montana-Dakota's and OTP's participation in the AQCS Project. In terms of the joint plant ownership agreement, approval of two of the three owners is needed to decide on whether to proceed with the AQCS Project or any other course of action.

The Plant was constructed and operates as a baseload facility with load following capabilities. Load following is the ability for the unit to adjust its output between full load and partial load to meet the demands of the system.[1] The Plant is a cornerstone generation source for all three companies, comprising the largest baseload resource for each of the Co-Owners. The Plant also provides electricity, steam and water to the adjacent POET Biorefining Ethanol Plant.

The Big Stone Plant has a single generating unit. Its cyclone boiler was originally designed by Babcock & Wilcox to burn lignite fuel. The boiler is a Carolina-type balanced draft pump-assisted radiant unit. The unit was originally constructed with a Westinghouse steam turbine and generator. Through the years, due to maintenance problems and efficiency improvement, certain steam components have been replaced. The generator stator and rotor have been rewound, and the generator shaft was replaced in 1987 due to failure of the original rotor.

The Plant now receives its fuel from Wyoming, transported by the BNSF Railway Company. The Big Stone Plant burns low sulfur PRB fuel to limit sulfur dioxide emissions, but it is not currently equipped with a flue gas desulfurization system for control of sulfur dioxide emissions, commonly referred to as a scrubber. Particulate emissions are controlled by a baghouse, and an over fire air system provides nitrogen oxide control.

The Plant is a zero-liquid discharge facility, meaning that no process water used in Plant operations leaves the site other than through evaporation. Big Stone Lake is the water source for the Plant. Water can only be taken from the lake when lake levels are at or above levels prescribed in water appropriations permits issued by the South Dakota Department of Environment and Natural Resources (South Dakota DENR). The water is stored in a cooling

---

[1] For example, during certain times of the year the Plant's output will be low at night, as demand is low. The Plant will then increase output in the morning as the system load increases. Late in the evening the Plant will decrease its output as load decreases.

pond for maintaining water quality as well as a brine concentrator used to control water chemistry in the cooling pond.

The Big Stone Plant has a dry on-site ash disposal area permitted by the South Dakota DENR.

B. Requirement to Implement the Big Stone AQCS Project

The federal Clean Air Act established a national goal of remedying any existing and preventing any future impairment of visibility from man-made air pollution in specified "Class I" areas of the United States.[2] EPA promulgated the Regional Haze Rule ("RHR") in 1999 to address visibility impairment in these areas, and in 2005 published a revised rule that provided guidelines for control technology determinations under the RHR.[3] State environmental agencies like the South Dakota DENR and the North Dakota Department of Health (DOH) are required to submit State Implementation Plans ("SIPs") to EPA that develop and implement their strategy to reduce existing emissions that may contribute to regional haze, and to set additional reasonable progress goals toward meeting the goal of no man-made visibility impairment in Class I areas by 2064.[4]

Of the multiple CAA requirements for state regional haze programs, among the most significant requirements is the requirement to procure, install and operate Best Available Retrofit Technology ("BART") on major air emission sources, including existing electric generating units, that were placed into operation between 1962 and 1977.[5] The BART requirement is designed to determine appropriate air pollution control equipment to retrofit major air emission sources that were constructed before the applicability of the New Source Review program in the late 1970s.[6] The Big Stone Plant became operational in 1975 and is among the newer plants subject to the BART requirement.

Because the Big Stone Plant is located in South Dakota, the South Dakota DENR is the agency responsible for developing the SD Haze SIP, which includes the determination of BART emission controls for air emission sources in the state that are subject to the BART requirement. A regional haze SIP includes extensive emission and visibility impact analysis, establishment of goals for reasonable progress in improving visibility, development of a long term strategy, and

---

2 42 U.S.C. § 7479 (CAA § 169A).

3 40 C.F.R. §§ 51.300 to 51.309 ("Protection of Visibility") & App. Y ("Guidelines for BART Determinations Under the Regional Haze Rule").

4 For major air emission sources in North Dakota, including electric generating units located in North Dakota, the DOH developed a SIP that determines Best Available Retrofit Technology requirements for multiple facilities, and takes other action to reduce regional haze from North Dakota sources of air pollution.

5 *See* 42 U.S.C. § 7491(b)(2)(A) (CAA § 169A(b)(2)(A)).

6 While emission standards had been applied to electric generating units in other Clean Air Act programs before the late 1970s, the New Source Review program was not yet in place. The New Source Review program initiated the requirement that new major sources of air emissions install Best Available Control technology as part of their construction permit requirements. *See* 42 U.S.C. § 7475(a)(4) (CAA § 165(a)(4)).

determination of BART requirements for individual facilities.[7] The process of preparing the SIP also includes opportunities for public comment, consultation with Federal Land Managers, and review of proposed plans by neighboring states.

At the culmination of work begun in 2007, the DENR determined that Big Stone is both BART-eligible and subject to BART, based upon air dispersion modeling indicating that Big Stone reasonably contributes to visibility impairment in certain Class I areas in South Dakota, North Dakota, Michigan, and Minnesota.[8] The DENR therefore determined that BART must be installed on Big Stone. Section 6.0 of the SD Haze SIP, the section that explains the BART determination made for the Big Stone Plant, is provided as Attachment 1 to this Exhibit.

The Co-owners also assessed other anticipated environmental regulations and the costs that could be expected to be imposed to achieve compliance. That assessment is provided in Attachment 2 to this Exhibit.

Since BART is a case-by-case determination for each unit that is subject to BART, the DENR evaluated available control technology for particulate matter ("PM"), sulfur dioxide ("SO_2") and nitrogen oxides ("NO_X"), based on its technical feasibility, cost, non-air impacts, remaining useful life of the source, and projected reduction of visibility impacts.[9] After considering information on the available control technology options, the DENR assessed the visibility improvement to be expected from the installation of air pollution control technology on the Big Stone Plant, in eight different configurations.[10]

Based on its extensive technical analysis, the South Dakota DENR made a final determination that the following control technology constitutes BART for the Big Stone Plant:

- Selective Catalytic Reduction with Separated Overfire Air ("SCR," "SOFA," and collectively, "SCR/SOFA"), for NO_X, which provides the highest level of control of the control equipment found to be feasible;

---

7 South Dakota's full SIP contains these elements, and may be found online at: http://denr.sd.gov/des/aq/publicnotices/RegionalHazeSIPDraft.pdf.

8 In 2010 the South Dakota DENR determined that, based on air dispersion modeling results, the Big Stone Plant would be reasonably anticipated to contribute to an impairment of visibility at the following Class I Areas: Badlands National Park in South Dakota, Theodore Roosevelt National Park in North Dakota, Isle Royale National Park in Michigan, and Voyagers National Park and the Boundary Waters Canoe Area in Minnesota. The detailed technical analysis and associated modeling results are fully set forth in the SD Haze SIP, §§ 6.1.3, Otter Tail Power Company-Big Stone I, and 6.2, Otter Tail Power Company's Modeling Results.

9 *Id.* at §§ 6.3.1, Particulate BART Review, 6.3.2, Sulfur Dioxide BART Review, and 6.3.3, Nitrogen Oxide BART Review.

10 *Id.* at § 6.3.4, Visibility Impact Evaluations.

- Semi-Dry Flue Gas Desulfurization (FGD), for SO_2,[11] which provides slightly less than the highest level of SO_2 control of the control equipment found to be feasible, but which SD DENR found to have less visibility impact than the top-ranked option for SO_2, when modeled in combination with the selected NO_X and PM BART controls; and

- Baghouse, for PM, which provides the highest level of control of the control equipment found to be feasible.[12]

The emission limitations represented by installation of the above-listed control technologies on Big Stone were determined to constitute BART, and are required by the SD Haze SIP to be installed and operational as expeditiously as practicable but not later than five years from EPA's approval of the SD Haze SIP. The SD DENR submitted its SD Haze SIP to EPA on January 21, 2011. As part of the SD Haze SIP, South Dakota implemented its BART determination by placing the related emission limitations into its state rules.[13] Administrative Rules of South Dakota Chapter 74:36:21, provided as Attachment 3 to this Application, requires these controls to be installed on existing coal-fired power plants that are subject to BART by establishing the related emission limitations for SO_2, NO_X and PM that reflect the installation of the BART control technology.[14] The Big Stone Plant is the only plant in South Dakota to which this rule applies.[15]

The EPA could require changes in aspects of the SD Haze SIP as part of its review although the EPA has reviewed and provided comments to the South Dakota DENR throughout the development of the SD Haze SIP. EPA's latest comments to the DENR related to the form of the final emission limitations and their associated compliance monitoring requirements, and other parts of the SD Haze SIP not related to the Big Stone AQCS. The EPA did not disagree with the control technology chosen as BART for the Big Stone Plant, and adjustments to the

---

11 The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a baghouse for downstream particulate collection. This Petition addresses the spray dryer FGD process. Two other variations, the Novel Integrated Desulfurization (NIDTM) and Circulating Dry Scrubber are similar technologies that achieve similar levels of control effectiveness. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. Due to the similar nature of the different semi-dry technologies and the similar levels of control efficiency achieved by all the technologies, semi-dry technologies are grouped together for purposes of this Petition.

12 While the current baghouse represents BART, the baghouse will have to be replaced to accommodate the additional flue gas draft requirements that will be caused by the upstream installation of the semi-dry FGD and SCR/SOFA systems.

13 *See* SD Haze SIP, § 6.4, BART Requirements.

14 S.D. Admin. R. 74:36:21:06, BART Determination for a BART-eligible Coal-fired Power Plant, establishes the emission limitations for particulate, sulfur dioxide and nitrogen oxides. The rules were approved by the South Dakota Board of Minerals and Environment on September 15, 2010, and by the South Dakota Interim Rules Review Committee on November 17, 2010. The rules were filed with the South Dakota Secretary of State on November 17, 2010, and became effective twenty (20) days later, on December 7, 2010.

15 *See* SD Haze SIP, § 6.2, concluding that the Big Stone Plant is "the only source subject to BART in South Dakota."

form of final emission limits and compliance monitoring requirements would be extremely unlikely to change the determination of the control equipment required by the DENR under BART. This is especially the case given that the DENR chose the combination of controls predicted by air dispersion modeling to provide the greatest degree of visibility improvement of the options available.

The comparison of emission limitations in the Big Stone Plant's current South Dakota DENR air quality permit with the emission limitations that represent the DENR's BART determination are shown in Table 1.

Table 1 – Big Stone Emission Limits

	Current Permit	**BART Rule**
SO_2	3.0 lb/mmBtu	0.09 lb/mmBtu
PM_{10}	0.26 lb/mmBtu	0.012 lb/mmBtu
NO_X	0.86 lb/mmBtu	0.10 lb/mmBtu

According to South Dakota DENR's BART determination, the suite of control technologies to be implemented in the Big Stone AQCS reduce emissions to a level at which the Plant would not reasonably contribute to visibility impairment in the Boundary Waters and Voyager's Class I areas in Minnesota, Isle Royale National Park in Michigan, the Badlands National Park in South Dakota, and the Theodore Roosevelt National Park in North Dakota.[16]

C. Detailed Description of the Big Stone AQCS Project

The Big Stone AQCS Project consists of a semi-dry FGD system with a new baghouse, anhydrous-based SCR, SOFA, Activated Carbon Injection ("ACI"), and the associated ancillary balance-of-plant systems. The Plant's Co-Owners have included in the AQCS the design and installation of an ACI for control of mercury emissions in anticipation that such requirements will be imposed by the EPA within the timeframe of the AQCS Project construction schedule.[17] At OTP's request on behalf of the Co-Owners, Sargent & Lundy, LLC ("Sargent & Lundy") conducted a conceptual design study and prepared estimated costs for the AQCS needed to comply with the South Dakota DENR BART determination. The conceptual design is attached to this Exhibit as Attachment 4, and an updated cost estimate is included as Attachment 5. This section of the Exhibit describes the AQCS in detail, while the implementation schedule and cost of the AQCS Project are discussed in the sections that follow.

1. Semi-Dry Flue Gas Desulfurization

The semi-dry FGD system is focused on the control of SO_2 emissions, and includes spray dryer absorbers, a baghouse, lime and recycle preparation, and solid waste handling. The spray dryer absorbers and baghouse are installed on the Plant downstream of the air heater. In a semi-dry

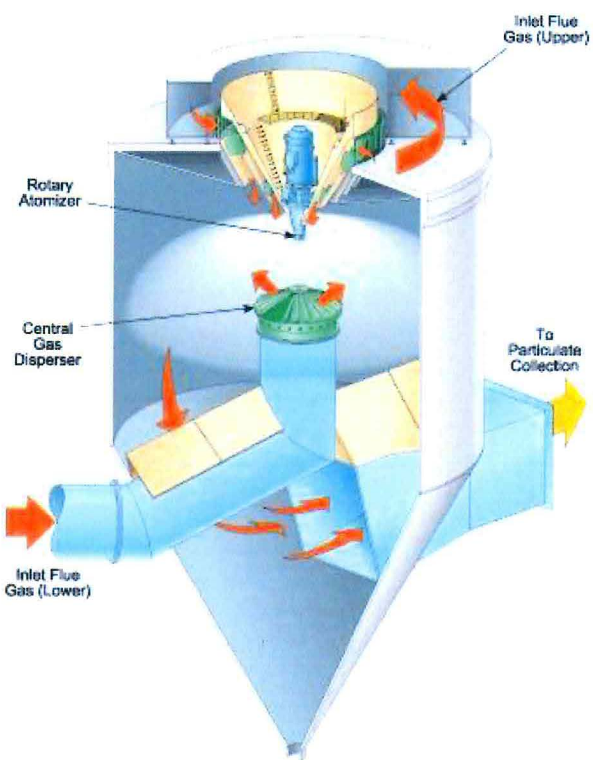
---

16 *See* SD Haze SIP, § 6.3.4, Visibility Impact Evaluations.

17 Because installation of the ACI system is proceeding in anticipation of the future requirement to control mercury emissions, the ACI system is part of Montana-Dakota's and OTP's requests for an ADP.

FGD system, flue gas is brought into contact with lime slurry in a spray dryer absorber (SDA) vessel. This process uses pebble quicklime (CaO) that must be hydrated before use. Pebble lime is delivered to the Plant site via truck and stored in a silo. Lime would then transfer to a slaker where the hydration (water mixed with lime) occurs. SO_2 absorption takes place in the SDA. Additional SO_2 removal takes place in the baghouse, downstream of the SDA. Calcium reacts with the SO_2 to form two waste solids, sulfate ($CaSO_4$) and sulfite ($CaSO_3$).

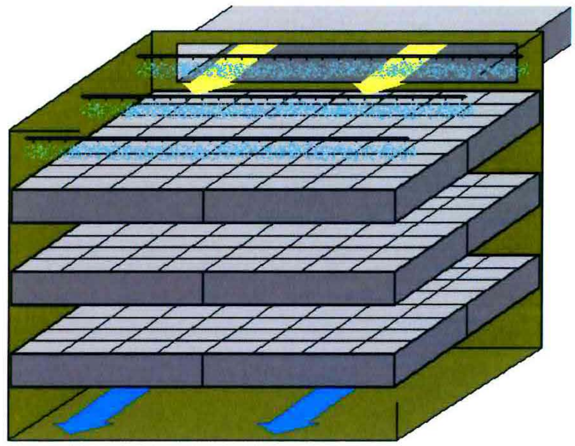
The dried solids are entrained in the flue gas, exit the SDA along with the fly ash from the boiler, and are then collected in a baghouse. Waste collected in the baghouse is pneumatically transported to either a waste storage silo or a recycle silo. The recycle silo is located above the waste slurry preparation area. From the recycle silo, the dry waste flows to a premix tank where it is combined with water. The slurry overflows to a recycle holding tank, which then overflows into a recycle slurry storage tank. This recycle system allows the lime to be passed through the SDA several times, mainly to reduce lime consumption. Semi-dry FGD waste not utilized in the recycle silo will be sent to a waste storage silo then loaded into trucks and sent to a landfill for disposal.



2. Selective Catalytic Reduction with Separated Overfire Air

SCR/SOFA technology is focused on the control of NO_X emissions. SCR is a post-combustion technology that uses catalyst elements, which are housed in a reactor that is installed in the flue gas stream upstream of the air heater. The process utilizes ammonia, which reacts with NO_X in the presence of a catalyst to reduce the NO_X to nitrogen and water.

Ammonia is injected into the flue gas stream well ahead of the catalyst, so the ammonia and NO_X are uniformly distributed as they reach the catalyst. The target temperature window for the flue gas is 625°F ± 25°F to 750°F ± 25°F. Flue gas exiting the SCR reactor will contain low concentrations of unreacted ammonia (called ammonia slip). Slip is limited to 2 ppmvd (parts per million, volumetric, dry) (at 3% O_2) at the SCR outlet. A higher slip value usually indicates that catalyst is beyond its life and is losing effectiveness at reducing NO_X.



The SOFA system is designed to provide optimum mixing of the balance of combustion air with the main combustion zone flue gas during the second stage of combustion within the furnace region of the Plant's cyclone boiler. The unique combustion characteristics of a cyclone furnace allow excellent NO_X reduction to be achieved while maintaining the balance of separated overfire air entry point into the boiler at close proximity to the cyclones themselves.

3. Activated Carbon Injection

ACI technology is focused on the control of mercury emissions. ACI uses powdered-activated carbon ("PAC"), which is pneumatically injected into the flue gas stream prior to the particulate collection equipment, to capture both elemental and ionic mercury ("Hg"). PAC is delivered to the Plant site by truck and pneumatically unloaded into a silo by a blower located on the truck. PAC is blown into the top of the silo and then settles to fill the vessel. Fluidized PAC is then transferred from the silo cone through a rotary airlock feeder into a gravimetric feeder. After the gravimetric feeder, the PAC is blown through a piping system and distributed to an array of injection lances that disperse the PAC into the cross-section of the flue gas ductwork upstream of the particulate control device. In the ductwork, PAC mixes with flue gas and the vapor-phase Hg is adsorbed on the surface of the PAC particle. The PAC particles then are captured in the particulate collection device.

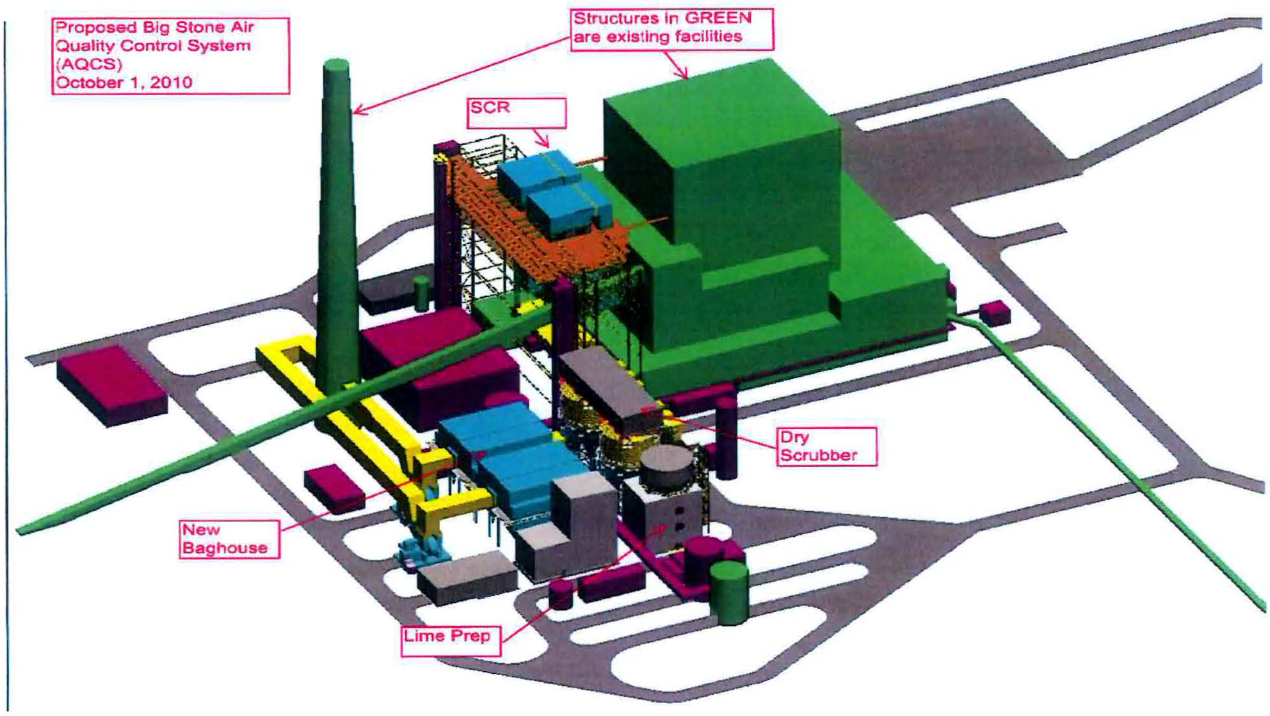
4. Balance of Plant Modifications

In order to install and successfully operate the control technologies that are part of the AQCS Project, the Co-Owners also must make the following balance of plant modifications at Big Stone:

- Modify the boiler to deliver flue gas at the required temperature for operation of the SCR and to maintain or improve boiler efficiency;

- Replace the existing baghouse;
- Replace the ID fans;
- Reinforce the boiler and duct work; and
- Modify the plant electrical infrastructure.

The following schematic depicts the AQCS system as it would be installed at the Plant.



D. Implementation Schedule

The SD Haze SIP and its implementing rules require that the Big Stone AQCS be installed, operated and shown to comply as expeditiously as practicable, but not later than five years from the EPA's approval of the SD Haze SIP.[18] As a result, if the EPA approves the SD Haze SIP in 2011, the Big Stone AQCS may be required to be installed and operational by 2016. To be in compliance by 2016, OTP must finalize the AQCS Project design and start procurement of major elements of the AQCS in early 2012.

---

[18] S.D. Admin. R. 74:36:21:07, Installation of Controls based on Visibility Impact Analysis or BART Determination; SD Haze SIP § 6.4, BART Requirements. The SD DENR submitted the SD Haze SIP to EPA on January 21, 2011.

The final deadline for BART compliance will be set by the EPA's approval date. In addition, EPA has the discretion to partially approve a SIP submittal, so there is also the possibility that EPA could decide to approve the Big Stone BART determination in advance of other elements of the SD Haze SIP. This leaves the Co-Owners under the obligation to proceed with the AQCS Project as expeditiously as practicable, and within the timeframe needed to meet a five year compliance deadline that could end by 2016.

The exact compliance deadline is not now known, and is not in the Co-Owners control to determine. The Big Stone AQCS is a large undertaking that will take several years to complete. The main implementation steps, if regulatory approval is received to proceed, include detailed engineering work in 2011, with procurement of major components of the AQCS starting in early 2012. The construction phase will continue into 2015. Once constructed, the AQCS would need to be tied in to the Plant, which would best be done during a scheduled outage of the Plant in 2015. Testing to demonstrate the compliance of the AQCS with the BART emission limits will need to occur within six months of the tie in of the AQCS with the Plant, and in time to start compliant operation before the final compliance deadline.

Attachment 5 to this Application includes a cost estimate and implementation schedule for the Big Stone AQCS Project which provides considerable detail on the steps and time periods involved in completing the project. This implementation schedule shows that the Big Stone AQCS is a five year project, not considering schedule slippage that could occur for a variety of reasons as a complex series of tasks are performed and coordinated over a substantial period of time.[19]

E. Cost Estimate

The estimate of the capital costs to install the AQCS Project at Big Stone, including the semi-dry FGD scrubber, SCR/SOFA, new baghouse and balance of plant changes, escalated to an in-service date of late 2015, is $489,397,400, with an accuracy of +/-20%. Installation of mercury control equipment on the Plant is estimated to cost an additional $5,012,700. The Co-Owners are recommending installation of the mercury control equipment at the time of the AQCS project as the requirement to control mercury emissions is anticipated to become effective within the time frame of the AQCS project. The EPA recently proposed National Emissions Standards for Hazardous Air Pollutants for Coal-Fired Utilities which requires mercury emissions reductions that would apply to the Plant. The rule was proposed on March 16, 2011, and is projected to be final by November 16, 2011. The compliance timeline of the proposed rule requires utilities with coal-fired units to install mercury controls to comply with the rule's established mercury emission limits by early 2015.

The capital cost estimate was prepared for the Plant's Co-Owners by Sargent & Lundy.[20] Sargent & Lundy was selected as the engineering firm for the AQCS Project as part of a request for proposal process that considered cost, experience and expertise. Sargent & Lundy was both

---

[19] Attachment 5 (Big Stone Plant AQCS Project Cost Estimate).

[20] Attachment 5.

the lowest cost firm and the firm that has performed the engineering on more projects like the AQCS Project than any other firm in the country. In particular, Sargent & Lundy has been involved with 57% of the dry FGD projects, 46% of the wet FGD projects and 30% of the SCR projects in the industry.

Sargent & Lundy's detailed explanation of the basis for the capital cost estimate was based on a conceptual design of the project and Sargent & Lundy's experience with similar projects.[21] Because OTP is at the early stages of the engineering process (only 2% of the engineering work has been completed), the estimate includes a contingency range of +/-20%.

The cost estimate has been compared to similar projects that Sargent & Lundy have completed, as adjusted for plant size and year in-service. The results on an equalized basis show that the cost estimate is consistent with other comparable projects. Large retrofit projects such as the AQCS Project at Big Stone typically contain very unique features that result from physical or operating constraints present at the existing plants. These unique conditions often make comparing one project to the other difficult. For example, some plants have considerable space available for new equipment while others are limited in space, and some plants have design margin in their auxiliary power systems, draft systems, etc., while other plants have no or limited available design margin in their existing systems. Consequently, the cost data from projects completed by Sargent & Lundy, as well as, publicly available data from semi-dry FGD and SCR projects completed in the years 2006 to 2010, fall within a fairly wide range of values from \$525/kw_g to \$850/kw_g in 2010\$. Using this cost range as a benchmark, the AQCS Project at Big Stone is consistent with other comparable projects in that the AQCS Project falls near the midpoint of the range of historical costs at a value of approximately \$617/kw_g.[22] In addition to the capital cost, there will be an additional ongoing cost to operate and maintain the AQCS equipment. It is estimated that in 2016, the expected first full year of operation, the additional cost to operate the equipment would be approximately \$11 million (including escalation).[23] The additional operating and maintenance cost would add approximately \$3.50 to the cost to produce a MWh of energy, or \$.0035 per kWh, based on the Plant's net dispatchable energy generation of 3,120,750 MWh. The total annual operating and maintenance costs for the Plant in 2016 with an AQCS will be \$27.3 million,[24] with the share to be borne by Montana-Dakota's North Dakota customers of approximately \$4.0 million and the share borne by OTP's North Dakota customers of approximately \$5.9 million. The biggest operational cost increase (approximately two-thirds

---

21 The cost estimate provided in Attachment 5 is a revision to an earlier less detailed cost estimate included in Attachment 4 (SO_2, NO_X, and Mercury Reduction Study) and reflects a substantial reduction in estimated costs for the AQCS Project due to a series of cost optimization decisions about the basic project design. The cost optimizations are summarized in a table describing 14 changes to reduce the estimated capital cost of the AQCS Project from that portrayed in Attachment 4.

22 The cost range and the \$617/kw_g estimate for the Big Stone AQCS Project do not include escalation beyond 2010 and AFUDC. Additionally, the Big Stone AQCS estimate does not include the substantial boiler modifications that are considered to be very unique to the Big Stone AQCS Project.

23 Attachment 6 (Big Stone AQCS Project Operating and Maintenance Cost Calculations).

24 *Id.*

of the operational cost increase) is caused by the lime and ammonia necessary to operate the SCR and semi-dry FGD, as well as the addition of employees at the Plant.[25]

The addition of control for mercury, which is likely to occur in the same timeframe, would add an operating and maintenance cost of approximately $2 million per year.[26] This would add approximately $0.65 to the cost to produce a MWh of energy, or $.00065per kWh.

F. Efforts to Insure Lowest Reasonable Costs

To ensure the lowest reasonable cost, the Co-Owners will: (1) use a request for proposal to select the lowest evaluated cost; (2) use a single erection contractor to manage installation to insure coordinated site work; (3) use separate requests for proposal for each major portion of the AQCS Project to allow for competition in the bidding process; and (4) aggressively manage the project to assure lowest reasonable cost.[27]

OTP on behalf of the Co-Owners, requested recommendations from Sargent & Lundy on how to manage the contracting process for the AQCS Project to insure that the project is implemented at lowest reasonable cost. Sargent & Lundy has a record of engineering and delivering AQCS projects at a lower cost than its competitors, and has worked on over half of the projects in the country that are similar to the AQCS Project. The analysis Sargent & Lundy provided is included as Attachment 7 to this Application.

Sargent & Lundy recommended an approach to managing the AQCS Project that will attempt to take advantage of favorable market conditions, but which will ensure the lowest reasonable cost if market conditions become more adverse as the AQCS Project is implemented. Under the recommended approach, the Co-Owners plan to solicit bids from suppliers for each major portion of the AQCS pollution control systems (the semi-Dry FGD, the SCR and the balance of plant modifications). This approach will allow the Co-Owners to go to the market sooner than is possible if the entire project must be developed as part of an Engineer Procure Construct solicitation. In addition, the Co-Owners plan to contract with a single erection contractor, to minimize the problems that can occur from multiple interfaces between numerous contractors. This approach will improve scheduling, resulting in better utilization of resources that will assist in achieving the lowest reasonable cost for the AQCS Project.

The Co-Owner's approach will avoid the potentially adverse costs of a date certain/price certain turnkey project, which could cost +/-10% or more (+/- $50 million). A turnkey approach, in addition to being too costly, would constrain the Co-Owners' ability to use the advantage to schedule early in the project through the procurement of equipment under current favorable market conditions, restrict the ability to select individual contractor combinations, disqualify potentially more cost-effective regional contractors who would not have the ability to bid on the

---

[25] Attachment 6; Attachment 4, Section 6.

[26] Attachment 6.

[27] If market conditions change greatly, this could result in changes in the contracting approach currently contemplated for the project.

project as a whole, restrict the Co-Owners' input during design development, and increase contingencies because the contractor's bid is based on less-developed engineering. Similarly, a contract approach using multiple suppliers and contractors managed by the Co-Owners has risks due to the complexity of interfaces between too many entities.

The Co-Owners' proposal strikes the proper balance by breaking the project into its fundamental building blocks: the different suppliers of pollution control systems and the erection work. Issuing requests for bids with more developed designs minimizes costs by reducing the contingencies that bidders would otherwise need to work into their proposed prices. The Co-Owners believe that this approach is the best approach to ensure that the AQCS Project is implemented at the lowest reasonable cost.

To keep interested parties and the Commission apprised of the implementation and costs of the AQCS Project, OTP and Montana-Dakota propose to set up a quarterly reporting mechanism with the Commission that would identify if there are any changed circumstances that will materially affect the cost of the AQCS Project.

G. Alternatives to Big Stone AQCS Project

The Co-Owners are proposing to undertake the Big Stone AQCS Project in order to comply with the SD Haze SIP and its associated implementing rules in order to continue operating a Plant representing a significant baseload resource for each utility. The SD Haze SIP specifies the control technology that represents BART for the Big Stone Plant and establishes emission limitations to reflect installation of the BART technology. The emission limitations reflect the emissions expected from installation and proper operation of an AQCS at the Big Stone Plant consisting of a semi-dry FGD, SCR/SOFA and baghouse. Because the BART requirement is a direct requirement that has been individually determined for Big Stone, the only alternative to installing the AQCS and achieving regulatory compliance is to cease operations at the facility. The Co-Owners have considered alternatives to the AQCS Project including the costs and benefits of retirement or repowering of the Plant with natural gas. The analysis of alternative response scenarios is provided in Joint Exhibit 2.

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

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

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

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

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

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

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

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

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

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

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

30 Attachment 9 at 6.

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 airsystem 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

[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.

---

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]	$74.38[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,

---

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]

---

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.

---

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 35% 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 40%, while adding the high environmental costs to the AQCS reduces the cost differential to 29%.[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)	$74.38	$100.43	$103.38	$117.25
Total Energy Cost Including Stranded Asset Cost	$74.38	$104.24	$107.19	$117.25
Total Energy Cost Including High Environmental Costs	$78.04	$100.43	$103.38	$117.25

b. Sensitivity Analyses

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 $66.24 MWh compared to $90.09 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 $82.51 MWh compared to $106.63 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 $66.24 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 $82.51 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 $72.21 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 $76.54 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

---

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.

---

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 35% 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.

IV. Montana-Dakota Exhibit 4 -MONTANA-DAKOTA'S ASSESSMENT OF PENDING ENVIRONMENTAL REGULATIONS TO THE BIG STONE PLANT

Montana-Dakota's analysis of the operational impacts of the alternative scenarios developed by OTP demonstrates that the AQCS Project should be implemented to assure that the current function of the Big Stone Plant in Montana-Dakota's system is maintained, including dispatchable baseload and load following capability. In contrast, the other alternatives would dramatically increase the exposure of Montana-Dakota's 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 Big Stone Plant represents a significant low cost baseload resource as part of Montana-Dakota's portfolio accounting for approximately 20 percent of the Planning Resource Credits required to meet the Midwest ISO's resource adequacy requirements while meeting approximately 23 percent of Montana-Dakota's retail customers' energy requirements. As a low cost producer the Big Stone Plant is also a significant contributor to wholesale sales that provide benefits to Montana-Dakota's retail customers.

Montana-Dakota separately analyzed the cost effectiveness of the Big Stone AQCS Project as part of its 2011 Integrated Resource Plan (2011 IRP) submitted to the Commission on May 12, 2011. As summarized in the Executive Summary of the IRP and as provided in more detail in the Supply Side and Integration Analysis in Attachment C of the 2011 IRP, the AQCS Project allowing the continued operation of the Big Stone Plant was modeled as a resource addition beginning in 2015. In Montana-Dakota's IRP, the AQCS project was compared with other alternatives to determine if it would be more cost-effective to retire the Big Stone plant or install the AQCS to continue the operation of the plant

The results of the Base Case analysis in the 2011 IRP and the results of each scenario modeled to test various sensitivities indicate that the AQCS Project is a least cost alternative to meet the capacity and energy requirements of Montana-Dakota's customers. The sensitivity scenarios consisted of various assumptions regarding carbon taxes, low and high natural gas prices, low and high load growth, high environmental costs, higher capital costs for combustion turbines, and higher costs for the Big Stone AQCS project. In the Big Stone AQCS scenario, the project cost was incrementally increased to determine at what point other alternatives would be selected over the Big Stone AQCS project. With the modeled cost of the Big Stone AQCS project nearly doubled from the original estimated cost, the project was still selected as part of Montana-Dakota's resource plan recommended in the 2011 IRP.

Montana-Dakota is not requesting any decision on cost recovery at this time. This Application is solely a request for an advance determination that it is prudent for Montana-Dakota to undertake the design, construction and operation of the Big Stone AQCS Project.

Montana-Dakota expects to seek cost recovery for the Big Stone AQCS Project through retail rates in future general rate cases or other cost recovery mechanisms. Montana-Dakota understands that it must show that the project costs are reasonable. (N.D. Cent. Code § 49-05-

16) Montana-Dakota further understands that the Commission may accept, modify, or reject any of the project costs found to be unreasonable in a future cost recovery proceeding, even though the Commission has made a determination that the Big Stone AQCS is prudent and should be implemented.