# BEFORE THE PUBLIC SERVICE COMMISSION

# OF THE STATE OF NORTH DAKOTA

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| **In the Matter of the Application of** | **)** | |
| **Montana-Dakota Utilities Co, a** | **)** | |
| **Division of MDU Resources Group, Inc.,** | **)** | |
| **for an Advance Determination of** | **)** | **Case No. PU-06-482** |
| **Prudence of Montana-Dakota's** | **)** | |
| **Participation & Ownership Interest in** | **)** | |
| **the Big Stone II Generating Station** | **)** | |

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# DIRECT TESTIMONY

# OF

# MARK ROLFES

**PROJECT MANAGER**

**OTTER TAIL POWER COMPANY**

**December 1, 2006**

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Direct Testimony of Mark Rolfes
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

# BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

# DIRECT TESTIMONY OF MARK ROLFES

## I. INTRODUCTION

**Q: Please state your name and job title.**

A: My name is Mark Rolfes. I am the Project Manager for the Big Stone Unit II Project, employed by Otter Tail Corporation d/b/a Otter Tail Power Company.

**Q: Describe your job duties.**

A: I am responsible for the overall coordination and implementation of the development of the Big Stone Unit II Project, including the interconnection facilities that are required to accommodate interconnection of the unit to the transmission grid.

**Q: Describe your educational background.**

A: I graduated in 1977 from North Dakota State University with a Bachelor of Science degree in Mechanical Engineering.

**Q: Please summarize your professional work history.**

A: I have been employed by Otter Tail for over 28 years in the Power Generation area. I began my career in coal-fired generation in 1977 as a Plant Engineer at the Big Stone Unit I site. In 1980 I became the Electrical Supervisor for Big Stone Unit I, responsible for the electrical, control and instrumentation functions of the Big Stone Unit I. In 1987 through 2001 I was Plant Manager of Big Stone Unit I, responsible for the overall operation and maintenance of the plant. From 1998 until 2001 I also had responsibility for the management of the Hoot Lake Station, a coal-fired plant located in Fergus Falls, Minnesota. In 2001 I was appointed to the position of New Business

Development for Otter Tail, which later transitioned into Project Manager for the Big Stone Unit II Project.

**Q: Are you a licensed professional engineer?**

A: Yes I am. I am a licensed Professional Engineer in the states of South Dakota and Minnesota.

**Q: What other professional experience have you had?**

A: I served on the Governor's Advisory Task Force on Hazardous Waste Management in the State of South Dakota. I have also served on numerous Electric Power Research Institute and Edison Electric Institute committees.

## II. PURPOSE AND SUMMARY OF TESTIMONY

**Q: What is the purpose of your testimony?**

A: The purpose of my testimony is to provide an overview of the Big Stone Unit II generation project in South Dakota and to address the various generation technologies that were considered before selecting a supercritical pulverized coal plant.

**Q: Please summarize your testimony.**

A: The Big Stone Unit II Co-owners evaluated several different alternative generation technologies before selecting Big Stone Unit II. The analysis determined that several alternative technologies were not feasible, and several, including a combination of wind energy "firmed" up by natural gas, were more expensive than the pulverized coal technology. I describe the time schedule for construction of the proposed new plant, which anticipates completion of construction in 2011 and commercial operation in 2012.

## III. BIG STONE UNIT II

**Q: Please explain how the Applicants intend to own Big Stone Unit II.**

A: Big Stone Unit II is intended to be owned as tenants in common, with each utility having an undivided interest in the entire project. The goal of the project's Ownership Agreement is to give all participants a voice in the decision making process and prohibit any utility from dominating the process. The expected ownership shares of Big Stone Unit II are as follows; Western Minnesota Municipal Power Agency (through Missouri River Energy Services) owning 25%; Great River Energy, Otter Tail, and Montana-Dakota Utilities Co. (Montana-Dakota) each owning 19.3%; Southern Minnesota Municipal Power Agency ("SMMPA") owning 7.8%); Central Minnesota Municipal Power Agency ("CMMPA") owning 5%; and Heartland Consumers Power District ("HCPD") owning 4.2%).

**Q: Explain how the Big Stone Unit II owner's group was formed.**

A: Two of the Big Stone Unit II ownership group – Otter Tail and Montana-Dakota – are participants in the existing Big Stone I power plant and also in the Coyote Unit located in Beulah, North Dakota. The agreements that govern these units have proven to be very successful for the many years these two plants have been in operation. Given this success, these agreements were a starting point for discussion on how Big Stone Unit II would be owned and managed.

**Q: Please explain what arrangements have been made between the Applicants on who would operate and maintain the proposed plant.**

A: The Applicants have entered into an Operating and Maintenance Agreement that governs the proposed operations of Big Stone Unit II. Under that agreement, Otter Tail would operate and maintain the unit. Otter Tail currently does this function for the existing Big Stone Unit I. It is planned that the two units would be operated together as a single facility. The Operating and Maintenance Agreement allows for the future change of an operating agent if the owners so desire.

**Q: Describe the general purpose for which the Big Stone Unit II in South Dakota is being proposed.**

A: Big Stone Unit II is being proposed to provide baseload electric generation for the seven Co-owners of the project. Baseload generation is generation available 24 hours a day, seven days a week. It is dispatchable, so that the output can be controlled by the participants to meet system needs. The energy is expected to serve the Co-owners' retail and wholesale native load customers. It is expected that Big Stone Unit II will generate in excess of 4.85 million megawatt-hours of energy annually.

The proposed Big Stone Unit II is a super-critical pulverized coal-fired electric power generating unit to be constructed adjacent to the existing Big Stone Unit I Plant. The project will generate approximately 630 megawatts (MW) net of electricity from a new coal-fired steam generation unit. Fuel for the project will be Powder River Basin (PRB) coal from a number of mines located in Wyoming and Montana, which is the fuel currently being burned at Big Stone Unit I. The facility will be designed to burn opportunity fuels in the new boiler, if feasible.

**Q: Please provide a general site description of the Big Stone Plant.**

A: The proposed site is adjacent to the existing Big Stone Unit I. The Big Stone Unit I site is located in northeastern South Dakota near Big Stone City, in Grant County. The site is approximately two miles northwest of Big Stone City, 1.7 miles from the nearest point of Big Stone lakeshore and approximately two miles from the Minnesota border. Because of the existing power plant, the site already has road access and rail access and has a plant makeup water facility that pumps water from Big Stone Lake to the Plant site. It has potable water and sanitary sewer, and it has existing transmission corridors.

**Q: Please describe the general criteria used by the Applicants to select alternative sites for the proposed project?**

A: Because of the service territories of the project participants, the first criterion considered was that the site should be located in one of three states – Minnesota, North Dakota, or South Dakota. The first review was to eliminate areas that were not suitable for consideration. These included places such as residential areas, National Parks, and recreational areas. The next criterion was the availability of infrastructure, such as rail lines, transmission corridors, and water supply. These were to provide the three main requirements for the plant site – a way to transport the fuel in, a way to ship the electricity out, and water needed for cooling. We also considered the potential environmental impacts associated with the plant site.

**Q: What process was followed for identifying candidate sites?**

A: Using the primary criteria described above, the Applicants conducted an initial screening to identify potential sites. Maps were prepared showing the various features that were important. From this work, the Applicants identified 38 potential sites. From this list, the Applicants narrowed the choice down to eight primary locations based on which potential sites best met the objectives described above. Next, these eight sites were inspected to better ascertain the availability of land, local land use, the existence of residences and other structures to the site, quality and quantity of transportation, access for rail delivery, and other infrastructure. Two of the eight sites were eliminated because of nearby residences and other developments and lack of sufficient land for development. The remaining six sites were retained for further analysis. Each of the six sites was evaluated for all of the criteria and ranked.

**Q: What six sites survived the initial screening and were ranked under the criteria?**

A: The six sites are:

- Big Stone - Grant County, South Dakota
- Coyote - Mercer County, North Dakota
- Dickinson - Wright County, Minnesota
- Fargo - Cass County, North Dakota
- Glenham - Walworth County, South Dakota
- Utica Junction - Yankton County, South Dakota

**Q: Please describe how these criteria were measured and weighted.**

A: Generally, water supply, fuel lines, and transmission were each given a weight of 20% and environmental issues and air quality specifically were each given 15%, and other factors such as highway access were given 10%.

**Q: What were the results of the ranking?**

A: The Big Stone site received the highest weighted score.

**Q: What are the advantages of the Big Stone site over the other five sites?**

A: The advantages of the Big Stone site are numerous. Most of them are due to the existing infrastructure. For the cooling water needed for the Plant, the existing pump-house and pipeline are adequate to support Big Stone Unit II without any changes. Big Stone Lake, the water source for Big Stone I, has adequate water availability. For fuel delivery, the existing rail spur and unloading facilities are adequate for a second unit without any modifications, thus also providing a substantial advantage. For solid waste, there is an existing ash disposal area that has adequate storage for both units for a number of years. There are also additional advantages to the site with the existing roadways, and the existing plant staff. Another advantage is that existing transmission corridors should minimize the impact of transmission additions. Another advantage of the site is the fact that residents in the area have gone through a plant construction and lived with the existing Plant for over thirty years. Last, the addition of a second unit at Big Stone provided an opportunity to construct a single common wet scrubber for both Unit I and Unit II. Because of the common scrubber, we expect sulfur dioxide emissions to be less from the two units than the current sulfur dioxide emissions from Unit I.

**Q: Are there any disadvantages to the Big Stone site as compared to the others?**

A: Yes, there are some disadvantages to the Big Stone site. One disadvantage of the site is the nature of the water supply. Water availability is dependant on lake elevation. The source of water for the project is Big Stone Lake; the water availability is set by South Dakota statutes for lake elevation. Thus, a certain amount of water storage for drought tolerance will be needed for the unit, even though there is more than adequate water during average conditions or a backup ground water source will need to be developed. Another potential disadvantage for the site is that it is served by a single rail carrier; it does not have rail competition. Another relatively minor disadvantage is that construction might be a little more difficult than at a new site because of the existing structures that will need to be worked around.

**Q: What is the estimate of the expected efficiency of the proposed Big Stone Unit II?**

A: The exact efficiency of the proposed project is not known at this time because final design determinations have yet to be made. Decisions on the particular equipment and vendors selected for the project will determine the final outcome of the project's efficiency. However, the Co-owners have made the decision to go with a super-critical steam cycle because that technology delivers higher efficiency than a subcritical cycle. Current projected heat rate for Big Stone Unit II is 8,988 BTUs per kilowatt hour. This means it will take 8,988 BTUs of energy from fuel to produce 1 kilowatt hour of electricity. This translates into an overall thermal efficiency of approximately 38%.

**Q: How much will Big Stone Unit II cost?**

A: The proposed Big Stone Unit II facility is projected to cost approximately 1.6 billion dollars (in 2011 dollars): 1.36 billion dollars for the plant and 238 million dollars for the transmission upgrades associated with the plant. The Co-owners are continually refining these cost projections.

**Q: Please describe the process for determining cost estimates for the Big Stone Unit II project.**

A: The process of determining cost estimates for the Big Stone Unit II project is similar to most large construction projects. It begins with a feasibility study to determine the likelihood of the project being successful. To do this a cost estimate is established for a generic plant. That is what was done for Big Stone Unit II in 2004. The cost estimate that was established in 2004 was then modified based on changes in the in-service date and for major design changes. The most notable change during the period from the initial feasibility study until the fall of 2005 was the decision to install a wet, rather than a dry, scrubber. The scrubber is the device for controlling $SO_2$ emissions. A wet scrubber uses a liquid reagent and is more costly but does a better job of controlling emissions than does a dry scrubber process. The feasibility study work was done by the Burns & McDonnell engineering firm. When the Co-owners determined that a supercritical unit with a wet scrubber appeared as the best option for their baseload generation needs, they decided to solicit bids from engineering firms to do the actual design work.

In the summer of 2005, the Co-owners selected Black & Veatch to be that firm. In October of 2005, shortly after they began work on the project, the Co-owners asked

Black & Veatch to do a quick "sanity check" on the numbers that we were using, which were estimates that had been prepared by Burns & McDonnell, also a large, respected engineering firm. This sanity check was a very brief review of other projects that Black & Veatch was involved in versus the cost that we were estimating for the Big Stone Unit II project. This sanity check showed that the cost estimates were reasonable, as they were squarely within the same range as the other projects on which Black & Veatch was working. Then, in early 2006, the Co-owners began to tighten down on the actual design parameters for the Big Stone Unit II.

At that time the project was transformed from a generic plant to a custom-designed plant based on the specifications selected by the Big Stone Unit II project Co-owners. Once the design parameters were established - and these included such things as the number of feedwater heaters, the cycle temperatures, the type of feed pumps that we plan to use, and many other parameters, Black & Veatch did a cost estimate based on the design and current market conditions. This information was supplemented with actual bids for five major components of the plant and indicative budgetary bids for others components of the plant. Then, the information was compiled along with non-plant items such as land procurement, project development, insurance, etc. and a total projected cost for the plant was delivered to the Co-owners in a proposed budget in July of this year.

After this, more precise cost information was in hand, we continued the engineering work to evaluate the prudence of the decisions made during the design process and to evaluate whether the estimated cost increases were reasonable, and whether things could be done to lower those costs. While on a different scale, the process the Co-owners employed is not significantly different than when someone decides to build a house. You get price estimates, and you determine whether some of the items that you included in your original design remain prudent. Since obtaining more precise cost information, we have been refining and adjusting to make a better, more cost-efficient plant.

Based on our adjustments, the projected cost has been reduced by approximately $165 million from the Black & Veatch report that we received in July.

Also, it should be noted that modifications to the plant design reflected in the Black & Veatch report have yielded a more efficient plant. We expect the unit to be 4% more efficient than originally projected, this means 4% less fuel consumed, and 4% less emissions. To increase efficiency, design changes have been made that have increased initial cost but that will reduce fuel costs. These changes include such things as an additional feedwater heater, steam driven boiler feedpumps, higher operating temperatures for the boiler and other related changes. These changes will also reduce operational maintenance costs. We have also seen some slight decreases in other operation and maintenance costs because of this improved efficiency and the more efficient operation of the scrubber and other equipment.

In addition, design review now suggests that a unit approximately 5% larger than what the original estimate was based on will result in greater plant efficiencies. Despite the 5% increase in size of the unit, the Big Stone Unit II Co-owners have committed to keeping emissions from both Unit I and Unit II of nitrogen dioxide, sulfer dioxide, and mercury to no more than what is currently emitted from Unit I (a 450 MW unit).

**Q: The Big Stone Unit II was originally sized at a nominal 600 MW. Now it is nominally sized at 630 MW. Please explain.**

A: As stated earlier, the proposed Big Stone Unit II is now approximately five percent (5%) larger than originally envisioned. The size of a power plant is somewhat akin to the gas mileage of a car. It is dependent upon many variables and no one ever seems to have exactly the result that they anticipate. To the extent there is any confusion over the size of the Big Stone Unit II, that is normal. All projects that I am aware of go through the same thing as the engineering conditions are defined. The proposed Big Stone Unit II plant conceptually began as a nominal 600 megawatt generic unit, meaning generally that on an average day the unit would produce 600 megawatts. As we began the design process, the Co-owners felt that they needed to have a unit that would reliably produce 600 megawatts during summer extreme conditions, and resulted in us specifying a unit that would produce 600 megawatts on a day defined as a "1% day." That is a day that is 95 degrees dry bulb, 76 degrees wet bulb. This is a day that is very hot and very humid, that happens 1% of the time or less. This means that during more average conditions, the unit would likely be producing approximately 630 megawatts. Again, it must be remembered that the actual output of any unit is dependent upon many conditions, most notably ambient air conditions (e.g., temperature and humidity).

**Q: What is the time schedule for construction of Big Stone Unit II?**

A: Assuming the project meets current permitting, financing, and commercial schedules, the mobilization of equipment to the site will begin in early 2008. Also, early in 2008, site work would commence with site preparation and then foundation installation. We hope to complete that in time for steel work to begin in early 2009. In late 2009 erection of the boiler and turbine would commence. In early 2010, construction of the balance of the plant equipment would commence. Installation of the boiler and turbine would be completed by early 2011. Once the boiler and turbine have been completed, preparation for the commissioning of this equipment would be started by a series of checkout procedures. The first time the unit would operate would then be late 2011, with commissioning and checkout commencing late 2011, for commercial operation in late spring or early summer 2012.

**Q: Did the Co-owners explore the possibility of generating power by means of renewable energy sources in this case?**

A: Yes, we did. We considered hydro, wind, solar, geothermal, and biomass.

**Q: Please describe the process the Co-owners followed to evaluate alternative energy sources?**

A: The process began with an initial screening of various alternatives to determine whether the alternative has the potential to address the need to be served by the proposed project, followed by an examination in more detail of only those options that appeared feasible. The Co-owners wanted to make sure that any generation alternative would be able to satisfy three basic objectives for a baseload generation unit – the technology must be applicable; the facility must be available for service when needed; and the facility should enhance the overall reliability of the bulk electric system.

**Q: What was the result of this evaluation?**

A: We determined that several renewable energy options were simply not feasible as a source of 600 MW of baseload generation; they did not meet the three basic objectives I described above. Hydro, solar, geothermal energy, landfill gas, fuel cells, microturbines, and wind too, were found to not meet these basic objectives.

**Q: Were there any generation alternatives that were examined in more detail?**

A: Yes, there were several. Importantly, it must be first remembered that each of the Co-owners determined through their respective resource planning processes whether a base load, pulverized coal unit such as Big Stone Unit II fit their respective resource needs, or more accurately, a portion of their needs. It is my understanding that each of those respective resource evaluations showed that such a resource was least cost.

After the Co-owners individually determined that they needed base load energy, and that a Big Stone Unit II was a fit for their needs, the Co-owners wanted to verify these separate conclusions. The Co-Owners hired Burns & McDonnell to evaluate in detail several generation alternatives, including a wind plus combined cycle natural gas combination, an integrated coal gasification combined cycle (IGCC) option, and 100% biomass option, although the biomass option was only for 50 MW. The 100% biomass option is surely a renewable energy source, the wind/gas combination is in part a renewable source since a portion of the power would be generated by wind. The Co-owners also had that analysis reperformed in October 2006, after they obtained cost projections based on the custom design of the plant. This updated analysis evaluated whether the Big Stone Unit II project remains a low cost baseload alternative.

**Q: What were the results of the examination of these generation alternatives?**

A: The results of the analysis are presented in the September 2005 Report entitled "Analysis of Baseload Generation Alternatives," and the October 2, 2006 report entitled "Revised Analysis of Baseload Generation Alternatives," both which are attached as Exhibit No. ______ (MR-1) and Exhibit No. ______ (MR-2), respectively. The analysis showed that a pulverized coal plant was the lowest cost option per unit of electricity of the alternatives examined.

**Q: What did the analysis show with regard to a wind alternative?**

A: Otter Tail, Montana-Dakota and the other Big Stone Unit II Co-owners recognize that wind will play a significant part in meeting the regional energy needs in the future.

Nonetheless, there are several reasons why wind cannot replace the Big Stone Unit II project. The major reason is that wind cannot be relied on to satisfy a base load demand. Electricity produced from wind is an intermittent resource. Wind turbines typically are only capable of achieving capacity factors in the range of 30 to 40 percent if properly sited in an area with adequate wind resources. This means that wind turbines only generate 30 to 40 percent of the megawatt hours that would have been generated if the units had run at full load continuously for the year. Base load generation is typically required to achieve capacity factors closer to 90%, and provide reliable energy on an around-the-clock basis. As a result, wind generation is not suitable to meet baseload capacity and energy needs.

Baseload resources are also required to be dispatchable, meaning that they can be scheduled to run at a specified load for a given duration. Since wind power is intermittent based on wind velocities, it is not dispatchable and not suitable as a baseload capacity and energy resource.

In order to even consider wind for base load power, it is necessary to have a backup source of generation to rely on when the wind is not blowing at the necessary speed. Burns & McDonnell evaluated a combination of 600 MW of wind, backed-up by a 600 MW combined cycle gas turbine. Wind energy would be utilized when it was available and the combined cycle unit would operate as necessary to back-up the wind's intermittency.

Under this scenario, the combined cycle natural gas plant would have the same economic and environmental implications as a combined cycle plant alone, including the volatility of and increased price of natural gas. Because the plant would be required to operate at part load dispatch levels, its heat rate would also be higher than a baseload CCGT unit. The "load following" required by the CCGT unit would also likely cause additional O & M costs over a baseload CCGT because of stresses due to continued turbine cycling.

The October 2006 Burns & McDonnell report assumes that the Co-owners would not own the wind turbines, but would have power purchase agreements for 600 MW of wind. The report also assumes no extension of the federal production tax credit of 1.9 ¢/kwh (adjusted for inflation) beyond 2007, though the report does include sensitivity analysis that assumes PTC extension.

The report assumes a price of $60/MWh for wind, which models show to be a good estimate of future wind prices without the PTC. With that assumption and assuming no costs for transmission and $7.60/MMBtu gas, Burns & McDonnell calculated a busbar cost for wind plus CCGT of $80.78 for investor-owned utilities.

This is significantly more expensive than the supercritical pulverized coal option being pursued, which has a busbar cost of $69.62 for investor-owned utilities.

**Q: Is a wind/natural gas combination less costly than the proposed Big Stone Unit II?**

A: Our best estimate under what we believe are the most reasonable assumptions, is that a pulverized coal plant like Big Stone Unit II is the most economic technology to address the resource needs identified by the Co-owners' respective resource planners, given all the factors related to size, type, and timing.

**Q: Does this conclude your testimony?**

A: Yes it does.

# Case No. PU-06-482
# Exhibit No.___(MR-1)

# Analysis of Baseload Generation Alternatives

## Big Stone Unit II

September 2005
39561

Burns & McDonnell
SINCE 1898

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# DEFINITION OF ACRONYMS & TERMS

| | |
|---|---|
| ASU | Air Separation Unit |
| Availability | The percent of time, on an annual basis, that a power generation resource is accessible to the utility to run based on hours that the resource is not down due to scheduled or forced outages. |
| B&McD | Burns & McDonnell |
| BACT | Best Available Control Technology |
| BSPII Plant or Project | New 600 MW coal fired generation plant at the existing Big Stone Plant near Milbank, South Dakota |
| Btu | British thermal units |
| Busbar Cost | Cost of electricity at the point of delivery from the generation source. Busbar cost does not include transmission costs. |
| Capacity Factor | The percentage of annual megawatt-hours generated compared to the annual megawatt-hours that would have been generated if the unit had run at 100% load continuously for the entire year. |
| CCGT | Natural Gas Fired Combined Cycle Gas Turbine |
| CFB | Circulating Fluidized Bed |
| CIAS | Center for Integrated Agricultural Systems |
| COD | Commercial On-line Date |
| CON | Certificate of Need |
| DCS | Distributed Control Systems |
| Dispatchable | The ability to schedule a power generation resource to run at a given load for a specified length of time |
| DOE | Department of Energy |
| EIA | Energy Information Administration |
| EPC | Engineer-Procure-Construct, which is a contract method where a single contract is entered into by the owner for the engineering design, equipment procurement and construction of the facility |
| FGD | Flue Gas Desulfurization system |
| HHV | Higher Heating Value |
| HP | High Pressure |
| HRSG | Heat Recovery Steam Generator |
| IDC | Interest During Construction |

| | |
|---|---|
| IGCC | Integrated Coal Gasification Combined Cycle |
| ILB | Illinois Basin |
| IOU | Investor Owned Utility |
| kWh | Kilowatt-hours |
| LHVTL | Large High Voltage Transmission Line |
| MCR | Maximum Continuous Rating |
| MDEA | Methyldiethanolamine |
| MMBtu | Million British thermal units |
| MW | Megawatts |
| MWh | Megawatt-hours |
| O&M | Operation and Maintenance |
| ppmvd | Parts per million by volume, dry basis |
| PRB | Power River Basin |
| PPU | Public Power Utility |
| PTC | Production Tax Credit |
| RP | Resource Plan |
| SCR | Selective Catalytic Reduction |
| Study | Analysis of Baseload Generation Alternatives |
| Subcritical PC | Subcritical Pulverized Coal |
| Supercritical PC | Supercritical Pulverized Coal |
| TBtu | Trillion British thermal units |
| WTE | Whole Tree Energy |

# Section 1

# Executive Summary

# 1.0 EXECUTIVE SUMMARY

## 1.1 INTRODUCTION

Seven utilities have proposed the joint development, permitting, construction, ownership, and operation of a new 600 MW coal-fired Big Stone II generation plant to be located at the existing Big Stone Plant near Milbank, South Dakota (BSPII Plant or Project). The seven joint ownership utilities include:

- Otter Tail Power Company (OTPCo)
- Central Minnesota Municipal Power Agency (CMMPA)
- Great River Energy (GRE)
- Heartland Consumers Power District (HCPD)
- Missouri River Energy Services (MRES)
- Montana-Dakota Utilities Company (MDU)
- Southern Minnesota Municipal Power Agency (SMMPA)

Each of the seven utilities, through their Resource Plan (RP) or internal resource planning efforts, has identified a need for additional baseload generation resources to serve their growing loads and/or to replace other resources in a reliable, cost-effective, and environmentally responsible manner. Joint ownership of the BSPII Plant allows the utilities to capitalize on the economies of scale of a larger baseload generation resource, capture the significant economic advantages of development of a baseload generation resource at an existing plant location, and mitigate risk in the construction and operation of a new baseload generation resource.

The BSPII Plant will necessitate the construction of new transmission lines to reliably deliver the output to the loads of the participating utilities. A Certificate of Need (CON) is required in Minnesota for a new Large High Voltage Transmission Line (LHVTL) pursuant to Minnesota Statutes, Chapter 216B. Burns & McDonnell (B&McD) was retained to perform an Analysis of Baseload Generation Alternatives (Study).

The Study focuses on six alternative baseload power plant technologies:

- Subcritical Pulverized Coal (Subcritical PC)
- Supercritical Pulverized Coal (Supercritical PC)

- Natural Gas Fired Combined Cycle Gas Turbine (CCGT)
- Wind Plus Gas-Fired Combined Cycle Gas Turbine (Wind + CCGT)
- Integrated Coal Gasification Combined Cycle (IGCC)
- 100% Biomass Plant

The Study evaluates the estimated busbar costs of the baseload generation alternatives to identify the most cost-effective technology for the joint participants. A summary of results from the Study are presented in Sections 1.2 through 1.8 of this report.

## 1.2 SUMMARY OF TECHNOLOGY ASSESSMENT BASIS

The capital cost estimates, performance estimates, emissions estimates, and operation and maintenance estimates are based on the following major assumptions:

- The construction of each alternative is executed under an Engineer-Procure-Construct (EPC) Contract, which is a contract method where a single contract is entered into by the owner for the engineering design, equipment procurement, and construction of the facility.
- Construction force is regional labor for the Big Stone City, South Dakota area.
- Cost estimates include escalation to support commercial operation in 2011.
- Primary fuel for the PC units is PRB coal.
- Primary fuel for the IGCC evaluation is eastern bituminous coal (Illinois No. 6).
- 100% dedicated wood crop (hybrid willow) is utilized for the biomass option.
- Owner's indirect costs are included.
- All O&M cost estimates are provided in 2005 dollars.

## 1.3 SUMMARY OF GENERATION ALTERNATIVES

B&McD developed planning level capital cost, operation and maintenance (O&M) costs, and performance estimates for the five different baseload generation technologies. The results of the technology assessment are presented in Table 1-1. These technical parameters are used as inputs to the economic model analysis discussed in Section 5. For the wind plus CCGT case, the wind component was assumed to be purchased at a levelized cost of $50/MWh and combined with a newly constructed combined cycle plant.

Table 1-1: Technology Assessment Summary

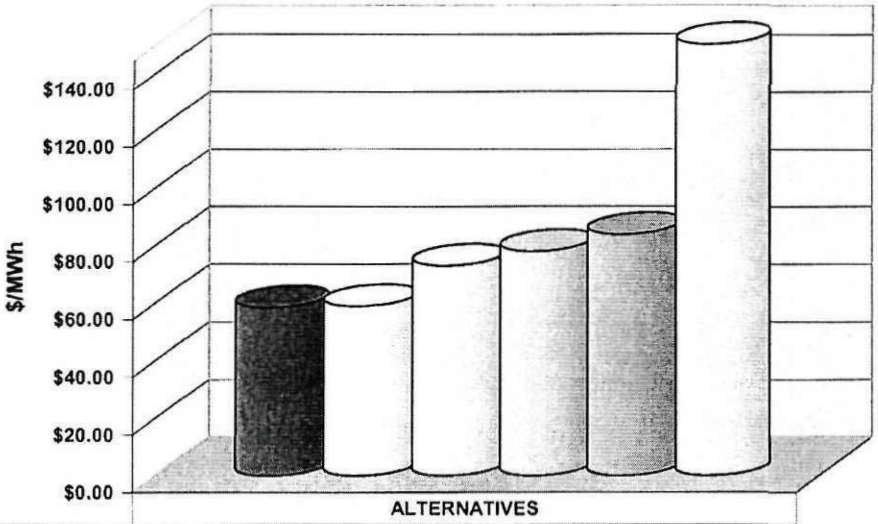
| PROJECT TYPE | 600 MW PC Supercritical New Big Stone Unit II | 600 MW PC Subcritical New Unit at Big Stone Site | 50 MW Biomass New Unit at Big Stone Site | 600 MW Combined Cycle Greenfield | 535 MW IGCC Greenfield |
|---|---|---|---|---|---|
| Technology Rating | Mature | Mature | Mature | Mature | Development |
| Number of Gas Turbines | N/A | N/A | N/A | 2 | 2 |
| Number of Boilers/HRSGs | 1 | 1 | 1 | 2 | 2 |
| Number of Steam Turbines | 1 | 1 | 1 | 1 | 1 |
| Steam Temperature (Main Steam / Reheat) | 1050 F / 1050 F | 1050 F / 1050 F | 950 F / N/A | 1050 F / 1050 F | 1050 F / 1050 F |
| Main Steam Pressure | 3500 psig | 2400 psig | 1250 psig | 1900 psig | 1900 psig |
| Steam Cycle Type | Supercritical | Subcritical | Subcritical | Subcritical | Subcritical |
| Fuel Design | 100% PRB | 100% PRB | 100% Biomass | 100% Natural Gas | 100% Bituminous |
| NOx Control | Low NOx Burners, SCR, OFA | Low NOx Burners, SCR, OFA | SNCR | Dry Low NOx Burners, SCR | Nitrogen Injection |
| SO2 Control | Wet Scrubber | Wet Scrubber | None | N/A | DLN, Amine Scrubber |
| Particulate Control | Baghouse | Baghouse | Baghouse | N/A | N/A |
| Ash Disposal | Landfill On Site | Landfill On Site | Landfill On Site | N/A | Landfill On Site |
| | | | | | |
| Net Plant Output, kW | 600,000 | 600,000 | 50,000 | 600,000 | 535,000 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 9,369 | 9,560 | 14,000 | 7,400 | 9,612 |
| | | | | | |
| Capital Cost, $/kW (2011 COD) | $1,800 | $1,765 | $2,983 | $605 | $2,126 |
| | | | | | |
| Fixed O&M Cost, $/kW-Yr (2005 USD) | $10.62 | $10.62 | $22.06 | $4.72 | $24.38 |
| Variable O&M Cost, $/MWh (2005 USD) | $2.23 | $2.24 | $2.69 | $3.20 | $5.91 |
| **CONTROLLED EMISSIONS** | | | | | |
| NOx, lb/MMBtu | 0.07 | 0.07 | 0.37 | 0.011 | 0.051 |
| SO2, lb/MMBtu | 0.10 | 0.10 | 0.025 | < 0.0051 | 0.061 |
| PM, lb/MMBtu | 0.015 | 0.015 | 0.018 | 0.015 | 0.012 |
| CO2, lb/MMBtu | 208 | 208 | 195 | 110 | 200 |
| Hg, lb/TBtu | 4.93 | 4.83 | N/A | N/A | 2.08 |

* Note: $NO_x$, $SO_2$, PM, and $CO_2$ are equivalent on a lb/MMBtu basis for the Subcritical and Supercritical PC Units. However, annual tons/yr of emissions will be lower from a Supercritical Unit since the greater efficiency of the Supercritical Unit will results in lower tons of coal burned per megawatt-hour.

## 1.4 SUMMARY OF ECONOMIC ANALYSIS

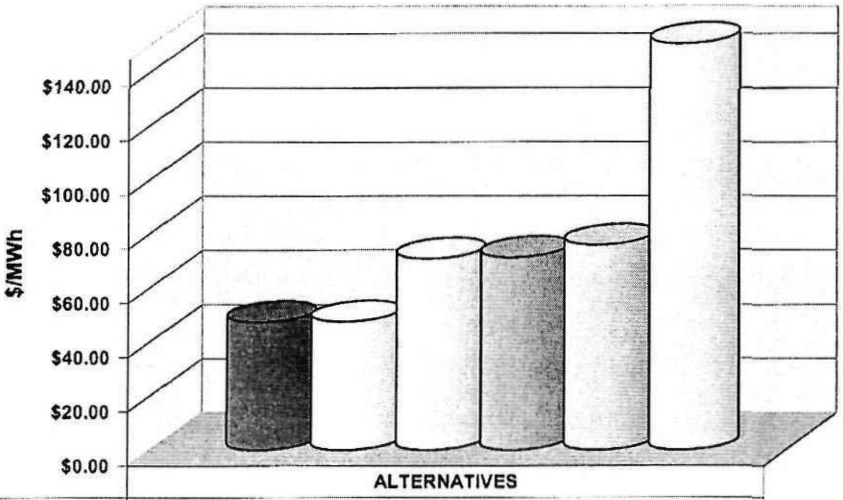
B&McD prepared an economic model analysis for each of the six baseload generation alternatives based on the cost and performance estimates presented in Table 1-1. A 20-year economic analysis was prepared and the levelized busbar cost of each alternative was determined under two ownership structures: investor-owned utility (IOU) and public power utility (PPU). Figures 1-1 and 1-2 present graphs showing the 20-year levelized busbar power costs in 2011$ for each of the baseload generation alternatives under both investor owned utility and public power utility ownership.

Figure 1-1: Levelized Busbar Costs (2011$) – Investor Owned Utility



| | ALTERNATIVES |
|---|---|
| ▨600 Sub PC IOU | $58.41 |
| ☐600 Super PC IOU | $58.81 |
| ☐600 Wind + CCGT IOU | $72.89 |
| ☐600 CCGT IOU | $77.94 |
| ☐535 IGCC IOU | $83.84 |
| ☐50 Biomass IOU | $170.52 |

Figure 1-2: Levelized Busbar Costs (2011$) – Public Power



| | ALTERNATIVES |
|---|---|
| ▨600 Sub PC PPU | $47.21 |
| ☐600 Super PC PPU | $47.37 |
| ☐600 Wind + CCGT PPU | $70.57 |
| ☐535 IGCC PPU | $71.05 |
| ☐600 CCGT PPU | $75.61 |
| ☐50 Biomass PPU | $156.02 |

As indicated in Figures 1-1 and 1-2, the PC unit alternatives represent the lowest cost baseload alternatives for the participating utilities and their customers. Although the combined cycle plant has lower capital costs, high natural gas fuel cost makes it uneconomical for baseload dispatch. The wind plus CCGT plant reflects the next lowest cost baseload resource choice, but is 24 percent higher cost for the IOU utilities and 49 percent higher cost for the public power utilities compared to the PC alternatives for baseload energy production.

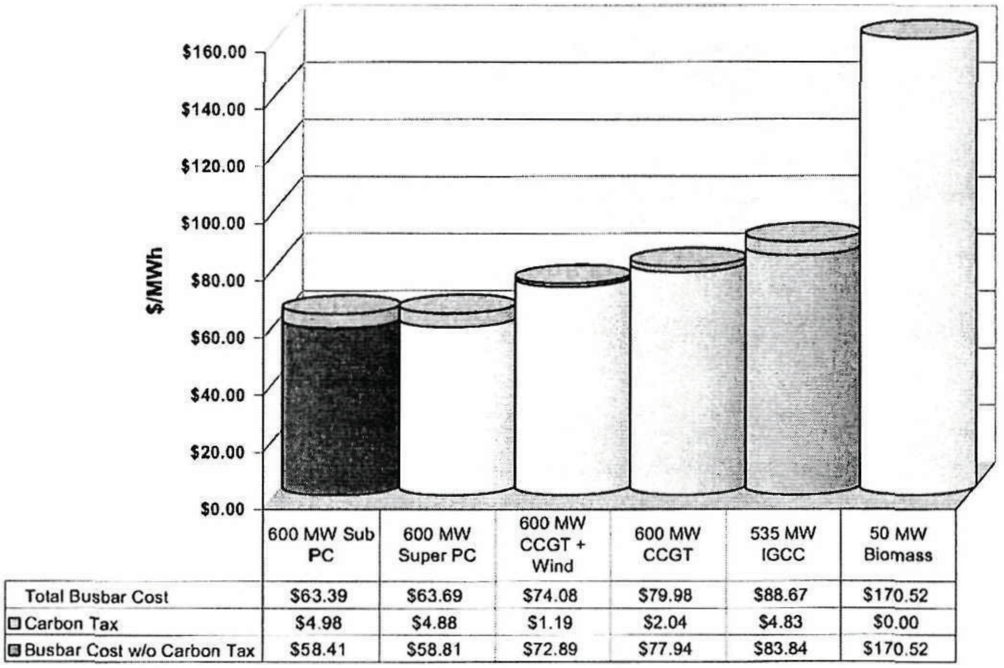
The overall economic difference between subcritical and supercritical PC technology is not material. The proposed BSPII Project will utilize supercritical PC technology in order to minimize emissions.

Sensitivity analyses indicate that capital cost and capacity factor are the two most significant factors affecting the economics of a coal-fired unit for an investor owned utility. For a public power utility, the interest rate and capital cost are the most significant factors affecting the economics of a coal-fired unit. Delivered fuel cost by far has the strongest impact on the overall economics of a combined cycle unit, or the wind plus combined cycle case. This is an important result since the market price of natural gas is inherently volatile and nearly impossible for a utility to control over a 20 year planning period. Coal-fired generation resources are more capital intensive than natural gas combined cycle plants, and have a construction period that can be more than twice the length of a combined cycle plant. This results in more capital risk due to interest costs, labor availability and costs, and general inflation. The primary tradeoff for these higher capital risks with a coal generation resource is the long-term stability of coal which has few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

## 1.5 SUMMARY OF CARBON TAX SCENARIOS

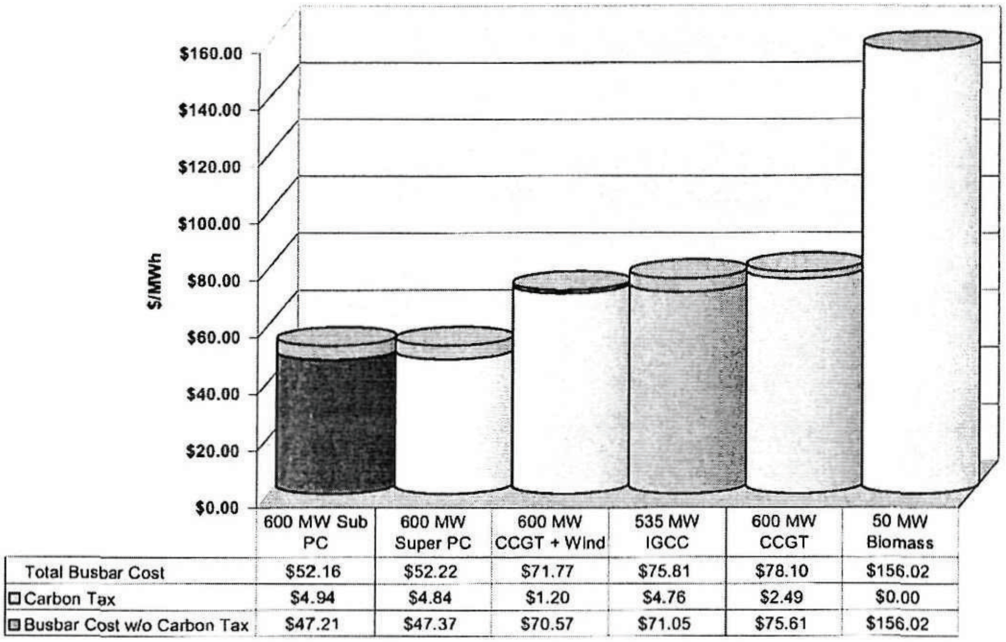
The Minnesota Public Utilities Commission has identified a range of values for a carbon dioxide externality of $0.35/ton to $3.64/ton. The inclusion of a carbon dioxide externality value, or imposition of a carbon tax, would cause an increase in the busbar cost of power for a new baseload resource. Figures 1-3 and 1-4 below present the impact of the $3.64/ton $CO_2$ externality value on the economic modeling results under both investor owned utility and public power utility ownership structures. The subcritical PC Unit will emit approximately 4.6 million tons of $CO_2$ per year. At a $3.64/ton $CO_2$ externality value, the levelized busbar cost will be increased by $4.98/MWh under investor owned utility ownership and the levelized busbar cost will be increased by $4.94/MWh under public power utility ownership.

Figure 1-3: Levelized Busbar Costs – Investor Owned Utility – $CO_2$ Externality



| | 600 MW Sub PC | 600 MW Super PC | 600 MW CCGT + Wind | 600 MW CCGT | 535 MW IGCC | 50 MW Biomass |
|---|---|---|---|---|---|---|
| Total Busbar Cost | $63.39 | $63.69 | $74.08 | $79.98 | $88.67 | $170.52 |
| □ Carbon Tax | $4.98 | $4.88 | $1.19 | $2.04 | $4.83 | $0.00 |
| ▨ Busbar Cost w/o Carbon Tax | $58.41 | $58.81 | $72.89 | $77.94 | $83.84 | $170.52 |

Figure 1-4: Levelized Busbar Costs – Public Power – $CO_2$ Externality



| | 600 MW Sub PC | 600 MW Super PC | 600 MW CCGT + Wind | 535 MW IGCC | 600 MW CCGT | 50 MW Biomass |
|---|---|---|---|---|---|---|
| Total Busbar Cost | $52.16 | $52.22 | $71.77 | $75.81 | $78.10 | $156.02 |
| □ Carbon Tax | $4.94 | $4.84 | $1.20 | $4.76 | $2.49 | $0.00 |
| ▨ Busbar Cost w/o Carbon Tax | $47.21 | $47.37 | $70.57 | $71.05 | $75.61 | $156.02 |

As indicated in Figures 1-3 and 1-4, the inclusion of a carbon externality or tax of $3.64/ton increases the levelized busbar costs of all the alternatives, but does not change the relative economics of the baseload generation resource choice.

The break-even carbon dioxide externality value to equalize the 600 MW supercritical PC unit levelized busbar cost with the 600 MW wind plus CCGT levelized busbar cost is approximately $14.00/ton in 2011 for the investor owned utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $77/MWh, which is an increase of 31 percent compared to the base case supercritical PC unit cost of $58.81/MWh.

The break-even carbon dioxide externality value to equalize the 600 MW supercritical PC unit levelized busbar cost with the 600 MW wind plus CCGT levelized busbar cost is approximately $23.00/ton in 2011 for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to $78/MWh, which is an increase of 65 percent compared to the base case supercritical PC unit cost of $47.37/MWh.

Overall, inclusion of a carbon externality value or carbon tax in the evaluation would not impact the baseload generation resource decision unless a significant tax or other cost was imposed.

## 1.6 CONCLUSIONS

The Analysis of Baseload Generation Alternatives supports the following conclusions:

- The subcritical and supercritical PC unit alternatives represent significantly lower cost baseload alternatives for the participating utilities and their customers.
- The higher construction costs of the IGCC alternative along with the higher bituminous coal fuel costs make this technology uneconomical in comparison to the PC unit alternatives, by significant margins. In addition, the IGCC technology should be considered a developing technology, and IGCC plants in the United States have not achieved high capacity factor operations with any consistency.
- The 50 MW biomass plant is not economically viable for baseload energy production due to higher construction costs and higher fuel costs. A larger scale biomass plant to take advantage of economies of scale in construction costs is not practical. A lower cost renewable option would be to co-fire a percentage of the heat input of the 600 MW BSPII Project with a wood residue, wood

crop, or agricultural waste. A five percent co-fire on a heat input basis would represent the equivalent of a 30 MW biomass plant.

- Although the CCGT alternative has lower capital costs, the high natural gas fuel cost, even under a natural gas cost forecast of $7.00/MMBtu for 2011, makes it uneconomical for baseload dispatch.
- The wind plus CCGT case reflects the next lowest cost baseload resource choice, but is 24 percent higher cost for the IOU utilities and 49 percent higher cost for the public power utilities compared to the PC alternatives for baseload energy production. This case assumes 600 MW of wind energy is purchased at a levelized cost of $50/MWh and a 40 percent capacity factor to displace gas-fired generation.
- The overall economic difference between subcritical and supercritical PC technology is not material. The subcritical PC unit is marginally more economically attractive than a supercritical PC unit. The proposed BSPII Project will utilize supercritical PC technology in order to minimize emissions.
- Coal-fired generation resources are more capital intensive than natural gas combined cycle plants. This results in more capital risk due to interest costs, labor availability and costs, and general inflation. The primary tradeoff for these higher capital risks with a coal generation resource is the long-term stability of coal which has few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.
- The economics of coal-fired generation for baseload energy production are robust for the different sensitivity analyses.
- Inclusion of a carbon externality value or carbon tax in the evaluation would not impact the baseload generation resource decision unless a significant tax or other cost was imposed.

## 1.7 STATEMENT OF LIMITATIONS

In preparation of this Study, Burns & McDonnell has made certain assumptions regarding future market conditions for construction and operation of a new power generating facilities. While we believe the use of these assumptions is reasonable for the purposes of this Study, B&McD makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in the Study will vary.

# Section 2

# Introduction

# 2.0 INTRODUCTION

## 2.1 BACKGROUND

Seven utilities have proposed the joint development, permitting, construction, ownership, and operation of a new 600 MW coal-fired generation plant to be located at the existing Big Stone Plant near Milbank, South Dakota. The seven joint ownership utilities include:

- Otter Tail Power Company (OTPCo)
- Central Minnesota Municipal Power Agency (CMMPA)
- Great River Energy (GRE)
- Heartland Consumers Power District (HCPD)
- Missouri River Energy Services (MRES)
- Montana-Dakota Utilities Company (MDU)
- Southern Minnesota Municipal Power Agency (SMMPA)

Each of the seven utilities, through their RP or internal resource planning efforts, has identified a need for additional baseload generation resources to serve their growing loads and/or to replace other resources in a reliable, cost-effective, and environmentally responsible manner. Joint ownership of the BSPII Plant allows the utilities to capitalize on the economies of scale of a larger baseload generation resource, capture the significant economic advantages of development of a baseload generation resource at an existing plant location, and mitigate risk in the construction and operation of a new baseload generation resource. For purposes of this study, baseload generation is defined as generation that is dispatchable, has a minimum capacity factor of 70%, and a minimum availability of 80%.

## 2.2 OBJECTIVE

The BSPII Plant will necessitate the construction of new transmission lines to reliably deliver the output to the loads of the participating utilities. A CON is required in Minnesota for a new LHVTL pursuant to Minnesota Statutes 2004, Chapter 216B. Burns & McDonnell was retained to perform an Analysis of Baseload Generation Alternatives.

Founded in 1898, Burns & McDonnell Engineering Company, Inc. is an internationally recognized architectural/engineering firm with headquarters in Kansas City, Missouri. Burns & McDonnell is ranked in the top 10 percent of the leading 500 U.S. design firms as published in the Engineering News Record

(ENR), and is one of the top 200 international design firms as published in recent issues of ENR. Burns & McDonnell provides a full range of engineering and consulting services to utility, government, institutional, military, commercial, and industrial clients. The Burns & McDonnell staff, currently numbering about 2,000 employee-owners, includes professional engineers, architects, geologists, planners, estimators, economists, computer and other technicians, and environmental scientists, representing virtually all design disciplines.

The objective of the Study is to evaluate the estimated busbar costs of different baseload generation alternatives to identify the most cost-effective technology for the joint participants.

This Study consisted of the following components:

- Technology Assessment Basis (Section 3)
- Baseload Generation Alternatives (Section 4)
- Economic Analysis (Section 5)
- Carbon Tax Scenarios (Section 6)

## 2.3 BASELOAD GENERATION ALTERNATIVES

The Study focuses on six alternative baseload power plant technologies:

| | | |
|---|---|---|
| • Subcritical Pulverized Coal (Subcritical PC) | 600 MW | New Unit at Existing Site |
| • Supercritical Pulverized Coal (Supercritical PC) | 600 MW | New Unit at Existing Site |
| • Natural Gas-Fired Combined Cycle Gas Turbine (CCGT) | 600 MW | Greenfield |
| • Wind Plus Gas-Fired Combined Cycle (Wind + CCGT) | 600 MW(each) | Greenfield |
| • Integrated Coal Gasification Combined Cycle (IGCC) | 535 MW | Greenfield |
| • 100% Biomass Plant | 50 MW | New Unit at Existing Site |

Each of the seven utilities, through their RP or internal resource planning efforts, has identified a need for additional baseload generation resources. Therefore, peaking resources such as gas fired combustion turbines and intermittent renewable resources such as wind or solar are not evaluated as stand alone alternatives in this Study. The output from wind turbines varies from zero load to full load based on wind velocity. Since wind velocity cannot be accurately predicted, the output from the turbines cannot be scheduled. Also, wind powered generation cannot typically achieve capacity factors greater than 35%-

45%. To ensure reliable baseload energy is available and dispatchable, a wind plus combined cycle case was included. This assumes 600 MW of wind energy is purchased by the utilities at a 40 percent capacity factor to displace higher cost gas-fired generation from a 600 MW CCGT plant. Conversely, the 600 MW CCGT plant can provide reliable capacity when wind resources are inadequate.

The options for a new unit at an existing site are based on construction at the existing Big Stone site in South Dakota. An existing site offers capital cost savings based on the reuse of existing infrastructure. Expansion of an existing site can also result in operating cost savings based on the lower incremental staffing requirements. The CCGT, IGCC and wind plus CCGT options are not located at the Big Stone site due to requirements for a natural gas line, which does not exist at the Big Stone Site. The cost estimates are based on a generic Greenfield site.

The Study is based on the use of low-sulfur Powder River Basin (PRB) coal for the PC unit alternatives, natural gas for the CCGT unit, a dedicated closed-loop wood crop (e.g., hybrid willow) for the biomass plant, and eastern bituminous coal (Illinois Basin) for the IGCC alternative. The IGCC unit is based on eastern bituminous coal rather than PRB since there is no IGCC operating history on PRB coals.

The baseload generation technologies are evaluated based on advantages/disadvantages, expected capital cost differentials, expected performance differences, operating considerations and costs, environmental issues and industry trends. The basis of the capital and operating cost estimates is outlined in Section 3. Each of the baseload generation technologies is reviewed in further detail in Section 4.

Section 5 presents the economic analysis to determine the expected levelized busbar costs of each baseload generation alternative over a 20 year planning period. Carbon tax scenarios are evaluated in Section 6 of the report.

# Section 3

# Technology Assessment Basis

# 3.0 TECHNOLOGY ASSESSMENT BASIS

## 3.1 GENERAL ASSUMPTIONS AND CLARIFICATIONS

This section provides overall assumptions that were used in developing the capital cost estimates, performance estimates, and O&M estimates for this technology assessment.

- The construction of each alternative is executed under an Engineer-Procure-Construct (EPC) Contract, which is a contract method where a single contract is entered into by the owner for the engineering design, equipment procurement, and construction of the facility.
- Construction force assumed to be regional labor for the Big Stone City, South Dakota area.
- Rail access is nearby and suitable for receipt of heavy equipment.
- The cost estimates include escalation to support commercial operation in 2011.
- No piles have been included. All foundations are assumed to be spread footings or mat foundations.
- Rock, existing structures, underground utilities, or other obstructions will not be encountered in the area of the plant.
- Hazardous substances will not be encountered in the area of the plant.
- No aesthetic landscaping or structures are included.
- Primary fuel for the PC units is PRB coal with 8,475 Btu/lb heating value, 0.30 percent sulfur content, 5.4 percent ash content, and 29.46 percent moisture.
- Because there is no long term IGCC operating experience on PRB coal, the primary fuel for the IGCC evaluation is eastern bituminous fuel (Illinois No. 6) with 10,400 Btu/lb heating value, 3.2 percent sulfur content, 10.6 percent ash content, and 13 percent moisture.
- Gas turbines, steam turbines, boilers, and FGD systems are located indoors.
- 100% dedicated wood crop (hybrid willow) is utilized for the biomass option.
- Rail is used for limestone and coal delivery.
- Trucks are used for biomass delivery.
- Wet cooling tower for heat rejection.

## 3.2 OWNER'S INDIRECT COST ASSUMPTIONS

B&McD included the following Owner's costs:

- Owner project management.
- Owner operations personnel (during construction/startup).
- Construction management.
- Permitting.
- Land.
- Owner's startup/testing costs.
- Site security.
- Operating spare parts.
- Permanent plant equipment and furnishings.
- Builder's risk insurance.
- Sales tax.
- Owner's contingency.

## 3.3 CAPITAL COST EXCLUSIONS

The following costs are excluded from the capital cost estimates:

- Transmission upgrades.
- Switchyard costs.
- Initial fuel inventory.
- Off-site road, bridge, or other improvements.
- Owner corporate staffing.
- Development costs.
- Financing costs including interest during construction (IDC)

Financing costs and interest during construction are incorporated separately in the economic modeling analyses.

## 3.4 OPERATION AND MAINTENANCE ASSUMPTIONS

The following assumptions provide the basis of the O&M cost estimates:

- The fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication and laboratory expenses.

- The additional staffing required for the PC units was estimated and added to the existing Big Stone Unit I staff. Half of the total staff from both units was included in the O&M cost estimates for Big Stone Unit II. This results in 52 staff members attributed to Unit II.
- The additional staffing required for the biomass option was estimated and added to the existing Big Stone Unit I staff. The staff was allocated such that 10% of the total staff is allocated to Unit II. This results in 9 staff members attributed to Unit II.
- The variable O&M includes makeup water, water disposal, limestone, ammonia, SCR replacements, solid waste disposal (on-site landfill), and other consumables not including fuel.
- All O&M cost estimates are provided in 2005 dollars.
- It is assumed that 80% of the flyash is sold to market at $3/ton. The other 20% of the flyash, bottom ash, and scrubber sludge is landfilled.
- The O&M cost of on-site waste landfilling is estimated at $5.24/ton and includes hauling, labor, and development of future landfill cells.
- Delivered limestone cost is included at $14/ton.
- Delivered ammonia cost is included at $535/ton.

The O&M estimates do not include fuel, property tax, insurance, or emissions allowance costs. These costs are incorporated separately in the economic modeling analyses.

## 3.5 EMISSION ASSUMPTIONS AND CLARIFICATIONS

The following assumptions are the basis for the emission estimates provided in the Study:

- The Best Available Control Technology (BACT) levels estimated for this Study are not definitive. BACT emission levels change with time, unit type, and fuel type. These emission rates represent B&McD's estimated BACT levels taking into account technology limitations and current expected guaranteed performance levels.
- The mercury emissions provided in the Study are the limits set by the Clean Air Mercury Rule, 40 CFR, Section 60.45 Da.
- The Clean Air Mercury Rule requires mercury emissions for a PC unit with a wet scrubber and firing PRB coal to be limited to $42 \times 10^{-6}$ lb/MWh. It is not anticipated that additional mercury control is required when firing an average mercury content PRB coal combined with a wet scrubber/baghouse. Therefore, the use of activated carbon injection is not included.

- The Clean Air Mercury Rule requires mercury emissions for an IGCC unit to be limited to $20 \times 10^{-6}$ lb/MWh. Mercury control for an IGCC is accomplished by filtering the syngas through a carbon filter bed.

# Section 4

# Baseload Generation Technologies

# 4.0 BASELOAD GENERATION TECHNOLOGIES

## 4.1 PULVERIZED COAL TECHNOLOGY

Pulverized coal (PC) technology is a reliable energy producer around the world. PC technology can be divided into two distinct designs which are distinguished by the maximum operating pressure of the cycle. The operating pressure of coal-fired power plants can be classified as subcritical and supercritical. Subcritical and supercritical technology refers to the state of the water that is used in the steam generation process. The critical point of water is 3,208.2 psi and 705.47°F. At this critical point, there is no difference in the density of water and steam. At pressures above 3,208.2 psi, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process.

Subcritical power plants utilize pressures below the critical point of water, whereas supercritical power plants utilize pressures above the critical point of water.

### 4.1.1 Subcritical

The majority of the steam generators operating in the United States utilize subcritical technology. These units utilize a steam drum and internal separators to separate the steam from the water. An example of a subcritical PC plant in Minnesota is the 884 MW Sherburne Unit 3.

In general, the steam cycle consists of one steam generator and one steam turbine generator. The balance of plant equipment consists of a condenser, condensate pumps, low-pressure feedwater heaters, deaerating feedwater heater, boiler feedwater pumps, and high-pressure feedwater heaters.

In the steam generator, high-pressure steam is generated for throttle steam to the steam turbine. The steam conditions are typically 2400 - 2520 psig and 1000°F-1050°F at the steam turbine. The steam expansion provides the energy required by the steam turbine generator to produce electricity.

The steam turbine exhausts to a condenser where the steam is condensed. The heat load of the condenser is typically transferred to a wet cooling tower system. The condensed steam is then returned to the steam generator through the condensate pumps, low-pressure feedwater heaters, deaerating heater, boiler feed pumps and high-pressure feedwater heaters.

Most subcritical units utilize a deaerating feedwater heater as the last low-pressure feedwater heater before the boiler feedwater pumps. This helps remove oxygen from the feedwater before entering the steam generator. Some operating units utilize a closed feedwater system in lieu of a deaerating feedwater heater. Typically in these units, a deaerating condenser is included in the system.

Coal is supplied to the unit through coal bunkers, then to the feeders and into the pulverizers where the coal is crushed into fine particles. The primary air system transfers the coal from the pulverizers to the steam generator burners for combustion.

Flue gas is transferred from the steam generator, through a selective catalytic reduction system (SCR) for $NO_x$ reduction and into an air heater. The flue gas then flows through particulate removal equipment and $SO_2$ removal equipment.

### 4.1.2 Supercritical

Supercritical boilers have been incorporated into the United States power generation mix since the mid 1950's. An example of a supercritical boiler in Minnesota is the 600 MW Allen King Unit 1, owned by Northern States Power Company. There are over 80 GW of supercritical units in the U.S., with the majority of units coming online before 1980, according to industry reports. At the same time, several new nuclear power plants were constructed for baseload capacity. Therefore, the supercritical plants were required to follow the utility load and were subjected to more cycling than anticipated. Due to a lack of high temperature materials, the existing materials were required to be fairly thick to withstand the operating conditions. The result was excessive valve wear, turbine thermal stresses and turbine blade solid particle erosion. This resulted in lower availability and higher maintenance costs than comparable subcritical units.

Since the start of the 1980s, the majority of supercritical units have been installed in Europe and Asia. The development of high strength materials has helped to minimize the thermal stresses that caused problems in the early units. The development of Distributed Control Systems (DCS) has helped make a complex starting sequence much easier to control and minimize tube overheating due to lack of fluid. The newer units also use a particle separator placed into the fluid process which allows recirculation of excess waterwall outlet fluid back to the waterwall inlet for loads below 35% Maximum Continuous Rating (MCR). Below that load, the unit is controlled similar to a drum type boiler, and a water level is maintained in the separator tank at the waterwall outlet, and feedwater flow to the unit is controlled to hold that water level. Below that load, the final steam temperature is controlled by spray water in the superheater attemperators. To ensure a minimum flow through the waterwalls during low load operation (35% MCR), a portion of feedwater is recirculated back to the waterwalls. Above 35% MCR load, the unit becomes "once through" and the feedwater flow is controlled through the ratio of firing rate to feedwater flow in order to hold a final high pressure (HP) main steam temperature setpoint.

Solid particle carryover to modern full arc throttling steam turbines has been reduced by the implementation of HP bypasses. All exfoliated solids from the oxidation of the superheaters breaks up and falls off during first fires and is dumped into the reheater and then to the condenser, bypassing the HP turbine's first stage and thus protecting the steam turbine. Therefore, many of the early problems with the units have been corrected.

The general description of the supercritical units is very similar to that of the subcritical units described earlier. The major difference is that the steam generator is a once through system and does not include a steam drum. Also, the feedwater system includes all closed feedwater heaters and typically does not include a deaerating heater.

Since there is no steam drum to allow blowdown of impurities in the system, water chemistry is critical to maintain a reliable system. A condensate polisher is typically incorporated into the condensate system to clean the condensate of impurities.

Many of the plants are also implementing an oxygenated water treatment system into their operation. An oxygenated water treatment system forms a ferric oxide hydrate on the inner surface of the steam generator. The traditional volatile system forms a magnetite oxide in the system. The advantage is that the ferric oxide is much less soluble; therefore the quantity of the oxide transported to the steam turbine is reduced.

Supercritical units are provided with essentially two types of tube arrangements: spiral or vertical. The spiral tube design has been utilized for more than 30 years. The primary disadvantage is the hardware needed to support the tubes during construction causes increased construction efforts. The spiral tube design also imparts additional friction drop in the system requiring larger boiler feedwater pumps. The vertical tube design has a much shorter history, but is gaining interest due to the reduced pressure drop and simpler configuration.

Below about 500 MW, all modern, variable pressure, once through units will need to employ a spiral wound furnace waterwall. Above about 500 MW, there is a possibility that the furnace waterwall can utilize a new design of a vertical rifled tube. The spiral wound design is more difficult to fabricate, install, and repair and collects more slag than a vertical-tubed furnace and also has a higher pressure drop. The vertical rifled tube design has a much lower pressure drop and is easier to fabricate, construct, and repair but has only been used on one coal fired furnace to date.

Most of the units built in the past twenty years in Europe and Asia have been the more efficient supercritical units due to the higher delivered cost of solid fuel in these areas. Supercritical units are also less sensitive to fuel variability than subcritical units, allowing the purchase of coal on the international spot market. A subcritical boiler has a limited range of fuels it can fire, due to the fact that each coal will affect the relative heat absorption rate in the furnace waterwalls and superheaters. For a subcritical unit, this affects the ability to achieve design final steam temperature and spray quantities. A supercritical unit, on the other hand, can always achieve design final steam temperature for all loads above 35% MCR simply by varying the ratio of firing rate to feedwater flow. This assumes the coal purchased can be processed by the mills, and be burned in the furnace without excessive slagging.

### 4.1.3 Performance

Based on B&McD's performance model, the operational heat rate for a 600 MW subcritical PC unit is estimated at 9,560 Btu/kWh (HHV) for steam conditions of 2,400 psig and 1050°F/1050°F (main steam/reheat steam).

Based on B&McD's performance model, the operational heat rate for the 600 MW supercritical PC unit is estimated at 9,369 Btu/kWh (HHV) for steam conditions of 3500 psig and 1050°F/1050°F. This represents an improvement of approximately 2.0 percent over the subcritical design. Emissions will also be 2.0 percent lower due to reduced fuel consumption. This results in approximately 31 tons per year less $NO_x$ emissions, 44 tons per year less $SO_2$ emissions, 4 pounds per year less mercury emissions, and 97,800 tons per year less $CO_2$ emissions.

### 4.1.4 Emissions

$NO_x$ emissions of a PC unit are controlled with Selective Catalytic Reduction (SCR). An SCR system installed in a PC unit burning PRB coal can reduce the $NO_x$ emissions to approximately 0.07-0.10 lb/MMBtu or below, although there is not significant operating history for SCR systems to date. For this Study, the $NO_x$ emissions for the PC units are expected to be 0.07 lb/MMBtu to meet expected Best Available Control Technology (BACT) requirements in South Dakota.

$SO_2$ control for PC Units is accomplished through the use of either a dry or wet flue gas desulfurization (FGD) system. A dry FGD system can achieve approximately 92% to 93% removal and a wet FGD system can achieve approximately 95% to 97% removal when using low sulfur coal. A wet scrubber is the technology selected for this study for the PC units to achieve low $SO_2$ emission rates and the co-benefits of lower mercury emissions. The $SO_2$ emission rate for the PC units is expected to be 0.10 lb/MMBtu to meet expected BACT requirements.

Particulate emissions are controlled by the use of a fabric filter (baghouse) or electrostatic precipitator (ESP). A baghouse is typically the preferred technology unless the sulfur content of the coal is high enough to cause deterioration of the bags. Since PRB coal has low sulfur content, a baghouse is anticipated for this project. The particulate emissions are estimated at 0.015 lb/MMBtu to meet the New Source Performance Standards and expected BACT requirements in South Dakota.

$CO_2$ emissions are uncontrolled and are estimated at 208 lb/MMBtu.

The mercury emission limit set by the Clean Air Mercury Rule for a PC unit with a wet scrubber and firing PRB coal is $42 \times 10^{-6}$ lb/MWh. This equates to approximately 4.93 lb/TBtu for the supercritical PC unit and 4.83 lb/TBtu for the subcritical PC unit. Actual mercury emissions may be less than the limits set by the Clean Air Mercury Rule.

The emission controls technology and emission rates (lb/MMBtu) for supercritical units and subcritical units are identical. Because supercritical units utilize less fuel than subcritical units, the emissions rates for supercritical units will be lower on a per kWh basis.

### 4.1.5 Waste Disposal

The byproducts from the combustion process and flue gas cleaning process are bottom ash, fly ash, and gypsum (since a wet FGD is used). The fly ash produced as a byproduct can be utilized as structural fill for developing new roads, or for a wet scrubber, can be used to supplement cement. The gypsum produced by a wet FGD system can be used for making wall board, however, no credit for gypsum sales have been included in this study.

For this assessment, it is assumed that 80% of the flyash is sold to market at $3/ton. The other 20% of the flyash, bottom ash, and gypsum is landfilled. The O&M cost of on-site waste landfilling is estimated at $5.24/ton and includes hauling, labor, and development of additional landfill cells in the future.

### 4.1.6 Capital Cost Estimates

The capital cost for a 600 MW subcritical pulverized coal plant utilizing a wet FGD system and a pulse jet baghouse is estimated at $1,765/kW (2011 COD) for a new unit at the existing project located at the Big Stone site.

The capital cost for a 600 MW supercritical PC unit located on the Big Stone Site is estimated at $1,800/kW. This is an increase of approximately 2% over a similar subcritical unit. The increased costs are in the boiler, steam turbine, boiler feedwater pumps, feedwater heaters, and piping.

### 4.1.7 Operation and Maintenance Estimates

The estimated fixed O&M of a 600 MW PC (subcritical and supercritical) unit at the Big Stone Site is $10.62/kW-yr, exclusive of property taxes and insurance. These costs are incorporated separately into the economic model analyses.

The additional staffing required for the PC units was estimated and added to the existing Big Stone Unit I staff. Half of the total staff from both units was included in the O&M cost estimates for Big Stone Unit II. This results in 52 staff members attributed to Unit II.

The non-fuel variable O&M of a 600 MW subcritical PC unit is estimated at $2.24/MWh, excluding emission allowances that are incorporated separately into the economic model analyses.

Variable O&M costs for a supercritical unit are slightly lower due to reduced lime, ammonia, and water consumption (due to less heat input). The non-fuel variable O&M of a 600 MW supercritical PC unit is estimated at $2.23/MWh, excluding emission allowances that are incorporated separately into the economic model analyses.

## 4.2 NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE TECHNOLOGY

### 4.2.1 Description

The basic principle of the combined cycle plant is to utilize natural gas to produce power in a gas turbine (GT), which can be converted to electric power by a coupled generator, but also use the hot exhaust gases from the GT to produce steam in a heat recovery steam generator (HRSG). This steam is then used to create additional electric power with a steam turbine and generator.

The use of both gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and low emissions. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Adding a steam turbine to the cycle, to utilize the steam produced by the HRSG, increases the efficiencies to a range of 52 percent to 58 percent.

Gas turbine manufacturers are continuing to develop high temperature materials to raise the firing temperature of the turbines and increase the efficiency. They are also developing cooling techniques to allow higher firing temperatures.

A 600 MW combined cycle is typically comprised of two gas turbines, two HRSGs, and single steam turbine. In order to reach 600 MW, the HRSGs will have to be heavily duct fired with additional natural gas. This is referred to as a 2x1 combined cycle gas turbine (CCGT) configuration.

### 4.2.2 Performance

Based on B&McD's performance model, a 2x1 CCGT utilizing General Electric 7FA gas turbines will produce approximately 600,000 kW at a net plant heat rate of 7,400 Btu/kWh (HHV) while duct firing. This performance is based on ambient conditions of 90°F, 30% RH, and 967 ft. elevation with the duct burner in operation.

### 4.2.3 Emissions

For a CCGT plant burning natural gas, low $NO_x$ combustors in the gas turbine, coupled with selective catalytic reduction (SCR) is typically utilized to achieve a NOx emissions level around 2.0-3.0 ppmvd at 15 percent $O_2$. The SCR system utilizes ammonia injection to achieve the NOx levels required. The resulting NOx emission rate is approximately 0.011 lb/MMBtu.

Sulfur dioxide emissions are not controlled and are therefore a function of the sulfur content of the fuel burned in the gas turbines. $SO_2$ emissions are expected to be below a negligible 0.0051 lb/MMBtu using "typical" pipeline quality natural gas.

Particulate emissions for combined cycles can vary greatly depending on sulfur content of the fuel. The sulfur in the exhaust gas will react with the ammonia in the SCR to produce ammonia salts, which are a form of particulate. It is expected that particulate emissions will be less than 0.012 lb/MMBtu utilizing "typical" pipeline quality natural gas.

$CO_2$ emissions are uncontrolled and are estimated at 110 lb/MMBtu.

CCGT plants that do not burn fuel oil do not have mercury emissions.

### 4.2.4 Waste Disposal

Waste disposal is negligible. Since the fuel to be burned is natural gas, no solid byproducts occur from the combustion.

### 4.2.5 Capital Cost Estimates

Project capital costs for a 2x1 7FA combined cycle facility located at a greenfield site are estimated at $605/kW (2011 COD). There is no natural gas available at the Big Stone site, and the capital cost estimate is based on a generic greenfield installation.

### 4.2.6 Operation and Maintenance Estimates

The fixed O&M for a 600 MW combined cycle unit is estimated at $4.72/kW-yr for a greenfield facility, exclusive of property taxes and insurance. These costs are incorporated separately into the economic model analyses.

The non-fuel variable O&M of a 600 MW combined cycle unit is estimated at $3.20/MWh, excluding emission allowances that are incorporated separately into the economic model analyses.

## 4.3 INTEGRATED GASIFICATION COMBINED CYCLE TECHNOLOGY

### 4.3.1 Description

Integrated Gasification Combined Cycle (IGCC) technology produces a low calorific value syngas from coal, petroleum coke, or heavy fuel oil that is then fired in a combined cycle plant or utility boiler. The gasification process represents a link between solid fossil fuels such as coal and existing gas turbine technology.

Integrating proven gasifier technology with proven combustion turbine combined cycle technology has been quite successful in applications utilizing fuels such as petroleum coke, asphalt, visbreaker tar, fluid coke, cracked tar, and heavy residual oil. However, utilizing coal as a solid feedstock in a gasifier for electrical power generation is more accurately described as still in the development stage.

Three gasifier manufacturers have IGCC experience on various U.S. coals. Each of the manufacturers has a slightly different technology that has proven to work differently on different fuels. Testing of various coals on the different gasifiers is continuing. There are a number of power generation projects jointly funded by the Department of Energy (DOE) at several power plant facilities throughout the United States (Refer to Table 4-1). Of the currently operating IGCC facilities, none is operating on low sulfur Powder River Basin coal.

A 2x1 IGCC plant would typically be comprised of two coal gasifiers, a coal handling system, an air separation unit, a gas conditioning system to remove sulfur and particulate, two gas turbines, two heat recovery steam generators with supplemental duct firing and a single steam turbine.

Integrating proven gasifier technology with proven gas turbine combined cycle technology is a relatively recent development, and continues to be improved at the existing DOE jointly funded power plants. Because gasification-based power generation is a relatively new technology with few operating plants, its unique operating features and its environmental performance capability are not well known.

Gasifiers designed to accept coal as a solid fuel generally fall into three categories: entrained flow, fluidized bed, and moving bed.

Entrained Flow

The entrained flow gasifier reactor technology converts coal into molten slag. This gasifier design utilizes high temperatures with short residence time and will accept either liquid or solid fuel. General Electric (Chevron Texaco), Conoco Phillips (E-Gas), Prenflo, and Shell, all produce gasifiers of this design.

Fluidized Bed

Fluidized-bed reactors are highly back-mixed design in which feed coal particles are mixed with coal particles already undergoing gasification. Fluidized bed gasifiers accept a wide range of solid fuels, but are not suitable for liquid fuels. The KRW and High Temperature Winkler designs use this technology.

Moving Bed

In moving-bed reactors, large particles of coal move slowly down through the bed while reacting with gases moving up through the bed. Moving-bed gasifiers are not suitable for liquid fuels. The Lurgi Dry Ash gasification process is a moving bed design and has been utilized both at the Dakota Gasification plant for production of synthetic natural gas and the South Africa Sasol plant for production of liquid fuels. BGL is another manufacturer of the moving bed design.

The majority of the DOE test facilities utilize the entrained flow gasification design with coal as feedstock. Coal is fed in conjunction with water and oxygen from an air separation unit (ASU) into the gasifier at around 450 psig where the partial oxidation of the coal occurs. The raw syngas produced by the reaction in the gasifier exits at around 2400 °F and is cooled to less than 400 °F in a gas cooler, which produces additional steam for both the steam turbine and gasification process. Scrubbers then remove particulate, ammonia (NH3), hydrogen chloride and sulfur from the raw syngas stream. The cooled and treated syngas then feeds into a modified combustion chamber of a gas turbine specifically designed to accept the low calorific value syngas. Exhaust heat from the gas turbine then generates steam in a heat recovery steam generator (HRSG) which in turn powers a steam turbine. However, the syngas cooler greatly improves thermal efficiencies when compared to a quench cooler system typical to those utilized in chemical production gasifiers. Reliability issues associated with fouling and/or tube leaks within the syngas cooler have challenged the existing IGCC installations.

The following table identifies the DOE jointly funded test facilities constructed in the United States, with various gasification system designs.

Table 4-1: IGCC Test Facilities

| Facility | Owner | Capacity (MW) | Commercial Operation Date | Gasifier Manufacturer | Location | % Funded by DOE | Status |
|---|---|---|---|---|---|---|---|
| *Polk County* | Tampa Electric | 252 | 1996 | Chevron Texaco | Polk County, FL | 25% | Operating |
| *Wabash River* | PSI Energy | 262 | 1995 | Conoco Phillips | Terre Haute, IN | 50% | Operating |
| *Pinon Pine* | Sierra Pacific | 99 | 1997 | KRW | Reno, NV | 50% | Decommissioned |
| *LGTI* | Dow Chemical | 160 | 1987 | Conoco Phillips | Plaquemine, LA | N/A | Decommissioned |
| *Cool Water* | Texaco | 125 | 1984 | Chevron Texaco | Barstow, CA | N/A | Decommissioned |

In addition to the constructed units referenced in Table 4-1, the following IGCC projects are currently in the development phase in the United States:

- 540 MW power station located in Lima, OH for Global Energy, Inc.
- 530 MW Mesaba Energy Project located in Minnesota for Excelsior Energy.
- 285 MW Stanton Energy Center Project in Florida, jointly owned by Orlando Utilities Commission and Southern Company.

Commercial operation of these plants, provided the projects proceed, is several years in the future.

### 4.3.2 Performance

Based on B&McD's performance model, a 2x1 IGCC facility is estimated to have an output of approximately 535 MW at a heat rate of 9,612 Btu/kWh (HHV). A comparable 600 MW output to the PC unit and CCGT unit alternatives is difficult to achieve for a 2x1 IGCC facility due to higher auxiliary loads of the air separation unit. For this reason, 535 MW is the maximum level of output available from a 2x1 IGCC facility, and is therefore used for comparison to the 600 MW PC and CCGT units.

### 4.3.3 Emissions

Nitrous oxide ($NO_x$) emission control is achieved by injecting either nitrogen or steam into the gas turbine combustors during syngas operation. During natural gas operation, steam injection is utilized for $NO_x$ control. Selective catalytic reduction (SCR) is not required at this time. The estimated BACT $NO_x$ emissions for a greenfield IGCC located in South Dakota is approximately 0.051 lb/MMBtu.

Sulfur dioxide ($SO_2$) emission control is achieved through sulfur removal in the syngas. Sulfur removal is accomplished by using an amine scrubber that utilizes a methyldiethanolamine (MDEA) solution to absorb hydrogen sulfide ($H2_S$) from the syngas stream prior to combustion. High levels of sulfur removal are accomplished by first passing the syngas through a carbonyl sulfide (COS) hydrolysis reactor prior to the amine scrubber to convert small amounts of COS in the syngas to $H2_S$. The estimated BACT $SO_2$ emissions for a greenfield IGCC located in South Dakota is approximately 0.061 lb/MMBtu.

The Clean Air Mercury Rule requires mercury emissions for an IGCC unit to be limited to $20 \times 10^{-6}$ lb/MWh. This results in a mercury emission rate of approximately 2.08 lb/Trillion Btu. Mercury removal is achieved by passing the syngas through a carbon filter bed prior to combustion.

The estimated BACT PM emissions for a greenfield IGCC located in South Dakota is approximately 0.012 lb/MMBtu. The syngas is scrubbed prior to combustion to remove particulate. Post-combustion particulate control is not required due to the inherently low particulate emissions of the syngas fuel.

Uncontrolled, $CO_2$ emissions from an IGCC facility are similar to a PC unit, and are estimated at 200 lb/MMBtu. The significant potential of IGCC technology is the ability to capture and sequester $CO_2$ emissions. For PC units, capture of $CO_2$ emissions would have to occur post-combustion, and there is no cost-effective method to accomplish the separation of $CO_2$ from the flue gas. For an IGCC facility, the syngas can be processed to separate $CO_2$ prior to combustion in the gas turbine. The Dakota Gasification plant utilizes the Rectisol process to strip $CO_2$ from the synthetic gas. The Dakota Gasification plant is not an IGCC facility, but a gasification plant that converts North Dakota lignite into a pipeline quality synthetic gas. The plant is located near Beulah, North Dakota and is owned and operated by Basin Electric Cooperative. The $CO_2$ that is recovered from the gasification process is compressed and piped to Canada where it is sequestered underground for enhanced oil recovery in the Weyburn oil fields.

While the technology exists for separation and capture of $CO_2$ in an IGCC facility, the cost is estimated to increase the overall busbar cost of electricity generation by 25%. For PC units, the Electric Power Research Institute (EPRI) has estimated that the comparable cost impact of $CO_2$ capture would be 70% on the cost of electricity. Once $CO_2$ has been captured, sequestration opportunities are limited and very site specific. Viable $CO_2$ sequestration opportunities include underground storage in limestone or saline caverns, or injection into deep wells for storage or enhanced oil recovery. Suitable subsurface conditions for $CO_2$ sequestration are not extensive throughout the US. $CO_2$ capture and sequestration is not included in this assessment.

### 4.3.4 Waste Disposal

The syngas sulfur removal process can result in 99.9 percent pure sulfur, which is potentially a saleable by-product. The gasifier converts coal ash to a low-carbon vitreous slag and flyash. The slag has beneficial use as grit for abrasives, roofing materials, or as an aggregate in construction. Fly ash entrained in the syngas is recovered in the particulate removal system and is either recycled to the gasifier or combined with other solids in the water treatment system and shipped off site for reuse or to be landfilled.

### 4.3.5 Capital Cost Estimates

The capital cost for a greenfield 535 MW IGCC facility is estimated at $2,126/kW (2011 COD). Due to the relatively poor reliability and availability performance of the first generation of IGCC facilities constructed in the United States, it is prudent to site and develop an IGCC facility with access to natural gas as backup fuel. *There is no natural gas available at the Big Stone site, and the capital cost estimate is* based on a generic greenfield installation.

### 4.3.6 Operation & Maintenance Estimates

There has not been a long operating history for IGCC units. The O&M expenses for a 535 MW IGCC unit are estimated to be $24.38/kW-yr fixed and $5.91/MWh for non-fuel variable O&M, exclusive of property taxes, insurance and emissions allowances. These costs are incorporated separately into the economic model analyses.

### 4.3.7 Long Term Development

The current largest U.S. coal IGCC facility is approximately 262 MW in size. Much of future IGCC technology development will be supported through government funding of Clean Coal Technology within the power industry. A few large scale (550 MW and greater) IGCC power plants are currently in the preliminary project development and/or permitting stage in the United States, however, commercial operation of these plants, if they proceed, is several years in the future due to long development, permitting, and construction timeframes for large solid fuel generation resources. Therefore, whether the next generation of IGCC facilities constructed in the US will have resolved the operational and reliability issues of the technology will not be demonstrated until 2010 or later. In contrast, the operational and reliability attributes of subcritical or supercritical PC is well demonstrated.

Acceptance of coal within the power industry and the relative price of natural gas will also influence the continuation and future development and commercialization of IGCC in the United States. Current technical issues which must be addressed and resolved for widespread commercialization of IGCC technology are expected to be addressed through future generations of government jointly funded large scale coal IGCC facilities. Once the development effort has been successfully completed, coal fueled IGCC technology may have the potential to be a reliable clean-coal generation within the United States. To date, gasifier manufacturers and IGCC contractors have shown reluctance to provide firm pricing to engineer, procure and construct an IGCC facility, or provide complete performance and emissions guarantees.

## 4.4 100% BIOMASS TECHNOLOGY

### 4.4.1 Description

The term "biomass" refers to any regenerative organic material used as a fuel for energy production, which can be grown, harvested, and re-grown. Biomass fuel typically consists of forestry materials, wood residues, agricultural residues and energy crops. Biomass crops are renewable, less polluting than conventional energy sources, and typically do not add to environmental levels of carbon dioxide. However, biomass fuels are scattered in supply and have various physical and chemical properties that can cause fouling or slagging. In general, biomass is bulky and expensive to transport; therefore, the plant site is typically located near the fuel source.

Using biomass as a fuel source is a mature technology. Biomass can either be burned directly or converted to gaseous or liquid fuels. Many types of boilers can be utilized depending on the fuel selection; the most common being a stoker boiler which is selected for this assessment. Circulating fluidized bed (CFB) technology is also used, but represents a higher capital cost than stoker technology for small scale applications. Wood-fired boilers are typically a derivative of older stoker type designs and range in size from 10 to 50 MW.

Examples of biomass crops include warm season grasses such as switchgrass, corn for ethanol, bio-solid waste, and wood such as hybrid willow. Switchgrass and wood are believed to have the highest potential for future electrical energy production.

A 1996-1997 Wisconsin study was conducted by a team from the Center for Integrated Agricultural Systems (CIAS), a team from the UW-Madison departments of agronomy and mechanical engineering, and researchers from the Wisconsin Department of Natural Resources. The study evaluated the use of switchgrass as a biomass crop. The conclusions found that when switchgrass is burned as a single fuel, potassium compounds in the grass are deposited in the combustion chamber causing excessive slagging. Therefore, switchgrass burned as single fuel is not recommended at this time.

Residues are the most economical biomass fuels for electricity. These are the organic byproducts of food, fiber, and forest production. Used shipping pallets and yard trimmings are also sources of biomass and are common near high population or manufacturing centers.

In the future, much larger quantities of biomass power could be supplied from fast-growing trees and crops, forest debris and thinnings, and non-hazardous wood debris diverted from landfills. In November 2000 a final report (*WTE$^{TM}$ Biomass Power Plant in Central Wisconsin*) was submitted to the Wisconsin Energy Bureau to obtain a grant for a 50 MW Whole Tree Energy (WTETM) biomass plant. The proposal indicated that the plant would be designed to burn whole trees in a deep fixed bed furnace. The fuel would be obtained by planting, growing, and harvesting trees in a five-year rotation. It would require approximately 50,000 acres of tree farms for a 50 MW boiler. This equates to 600,000 acres of land to support a 600 MW facility. 600,000 acres of land is the equivalent of approximately 940 sections of land, which is nearly double the size of the entire county of Big Stone County, Minnesota.

Much of the technology required for this Whole Tree Energy (WTE$^{TM}$) biomass plant is still in the development stage. This new technology includes a high speed tree planting machine, a high speed harvesting machine, a pilot scale deep bed furnace and gas scrubbing equipment.

One of the primary boiler vendors indicated their largest single biomass boiler would be approximately 65 MW. Because this would require approximately 10 boilers and 600,000 acres of regenerative biomass to produce 600 MW, a more feasible size was chosen for this evaluation. The technology selected for this Study is a 50 MW stoker boiler firing wood.

### 4.4.2 Performance

A 50 MW (net) biomass facility has a typical net heat rate of approximately 14,000 Btu/kWh (HHV).

### 4.4.3 Emissions

Emission controls for a biomass-fueled boiler can vary significantly depending on what type of fuel is utilized.

A 50 MW biomass stoker unit will likely require a SNCR system for $NO_x$ control. The estimated BACT emission levels for $NO_x$ on a biomass stoker unit are 0.37 lb/MMBtu.

Biomass fuels typically have low sulfur content (<0.1 percent by weight compare to 1-5 percent for coal), therefore, no additional $SO_2$ removal equipment is included for this alternative. Typically, scrubbers are not required for units that fire 100% biomass. The estimated BACT emission levels for $SO_2$ on a biomass stoker unit are 0.025 lb/MMBtu.

Particulate emissions are controlled by the use of a fabric filter (baghouse). The particulate emissions are estimated at 0.018 lb/MMBtu to meet expected BACT requirements in South Dakota.

$CO_2$ emissions are uncontrolled, but are not included in the assessment under the assumption that a dedicated wood crop fuel source represents a closed-loop biomass system with no net $CO_2$ emissions.

No mercury emissions are assumed in the assessment.

### 4.4.4 Waste Disposal

The ash from a biomass boiler is potentially a saleable byproduct that can be used as fertilizer and soil conditioner. For the purpose of this analysis, it was assumed that a market does not exist for this byproduct and an on-site landfill is used for disposal.

### 4.4.5 Capital Cost Estimates

The total capital costs for a 50 MW biomass unit located at the existing Big Stone Site are estimated at $2,983/kW (2011 COD).

### 4.4.6 Operation & Maintenance Estimates

The estimated fixed O&M of a 50 MW Biomass unit at the Big Stone Site is $22.06/kW-yr, exclusive of property taxes and insurance. These costs are incorporated separately into the economic model analyses.

The additional staffing required for the biomass plant was estimated and added to the existing Big Stone Unit I staff. The staff was allocated such that 10% of the total staff is allocated to Unit II. This results in 9 staff members attributed to Unit II, and reflects a conservative allocation of fixed staffing costs.

The estimated non-fuel variable O&M of a 50 MW biomass plant is $2.69/MWh, excluding emission allowances that are incorporated separately into the economic model analyses.

## 4.5 SUMMARY OF GENERATION TECHNOLOGIES

Table 4-2 below summarizes the generation technology alternatives presented in this section.

Table 4-2: Technology Assessment Summary

| PROJECT TYPE | 600 MW PC Supercritical New Big Stone Unit II | 600 MW PC Subcritical New Unit at Big Stone Site | 50 MW Biomass New Unit at Big Stone Site | 600 MW Combined Cycle Greenfield | 535 MW IGCC Greenfield |
|---|---|---|---|---|---|
| Technology Rating | Mature | Mature | Mature | Mature | Development |
| Number of Gas Turbines | N/A | N/A | N/A | 2 | 2 |
| Number of Boilers/HRSGs | 1 | 1 | 1 | 2 | 2 |
| Number of Steam Turbines | 1 | 1 | 1 | 1 | 1 |
| Steam Temperature (Main Steam / Reheat) | 1050 F / 1050 F | 1050 F / 1050 F | 950 F / N/A | 1050 F / 1050 F | 1050 F / 1050 F |
| Main Steam Pressure | 3500 psig | 2400 psig | 1250 psig | 1900 psig | 1900 psig |
| Steam Cycle Type | Supercritical | Subcritical | Subcritical | Subcritical | Subcritical |
| Fuel Design | 100% PRB | 100% PRB | 100% Biomass | 100% Natural Gas | 100% Bituminous |
| NOx Control | Low NOx Burners, SCR, OFA | Low NOx Burners, SCR, OFA | SNCR | Dry Low NOx Burners, SCR | Nitrogen Injection |
| SO2 Control | Wet Scrubber | Wet Scrubber | None | N/A | DLN, Amine Scrubber |
| Particulate Control | Baghouse | Baghouse | Baghouse | N/A | N/A |
| Ash Disposal | Landfill On Site | Landfill On Site | Landfill On Site | N/A | Landfill On Site |
| Net Plant Output, kW | 600,000 | 600,000 | 50,000 | 600,000 | 535,000 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 9,369 | 9,560 | 14,000 | 7,400 | 9,612 |
| Capital Cost, $/kW (2011 COD) | $1,800 | $1,765 | $2,983 | $605 | $2,126 |
| Fixed O&M Cost, $/kW-Yr (2005 USD) | $10.62 | $10.62 | $22.06 | $4.72 | $24.38 |
| Variable O&M Cost, $/MWh (2005 USD) | $2.23 | $2.24 | $2.69 | $3.20 | $5.91 |

Table 4-3 below summarizes the emissions rates for each of the technology alternatives presented in this section.

Table 4-3: Emissions Rates Summary

| **PROJECT TYPE** | **600 MW PC Supercritical New Big Stone Unit II *** | **600 MW PC Subcritical New Unit at Big Stone Site *** | **50 MW Biomass New Unit at Big Stone Site** | **600 MW Combined Cycle Greenfield** | **535 MW IGCC Greenfield** |
|---|---|---|---|---|---|
| NOx, lb/MMBtu | 0.07 | 0.07 | 0.37 | 0.011 | 0.051 |
| SO2, lb/MMBtu | 0.10 | 0.10 | 0.025 | < 0.0051 | 0.061 |
| PM, lb/MMBtu | 0.015 | 0.015 | 0.018 | 0.015 | 0.012 |
| CO2, lb/MMBtu | 208 | 208 | 195 | 110 | 200 |
| Hg, lb/TBtu | 4.93 | 4.83 | N/A | N/A | 2.08 |

* Note: $NO_x$, $SO_2$, PM, and $CO_2$ are equivalent on a lb/MMBtu basis for the Subcritical and Supercritical PC Units. However, annual tons/yr of emissions will be lower from a Supercritical Unit since the greater efficiency of the Supercritical Unit will results in lower tons of coal burned per megawatt-hour.

## 4.6 WIND PLUS COMBINED CYCLE

For the wind plus CCGT case, the 600 MW wind component was assumed to be purchased at a levelized cost of $50/MWh and combined with a new 600 MW constructed combined cycle plant based on the cost assumptions summarized above. The 600 MW wind component was assumed to provide energy at a 40 percent capacity factor. Because the CCGT plant would be required to operate at part load dispatch levels when combined with the wind generation, the heat rate assumption for the combined cycle plant in this case was increased 500 Btu/kWh to reflect part load dispatch requirements. No other operational issues or major maintenance impacts on the CCGT plant was incorporated in the analysis.

The estimated purchase cost of $50/MWh for wind resources is based on a 2011 commercial operation date. As such, it does not include the current Renewable Energy Production Tax Credit (PTC) that was extended to December 31, 2007 for wind resources as a result of the Energy Policy Act of 2005. The current PTC for wind energy is 1.9 cents/kWh. In a later section in the report, a sensitivity analysis was prepared assuming that the PTC is further extended or replaced with a similar tax credit. This would result in an estimated wind energy purchase cost of $38/MWh.

# Section 5

# Economic Analysis

# 5.0 ECONOMIC ANALYSIS

## 5.1 OBJECTIVE

B&McD prepared a number of economic model analyses of baseload generation technology alternatives. A twenty-year economic model analysis was prepared based on the estimated capital costs, performance, fuel costs, and operating costs of each Project alternative. The economic model analyses of each baseload generation alternative resulted in a levelized busbar cost that could be compared against one another.

## 5.2 ECONOMIC ANALYSIS ASSUMPTIONS

The following Project estimates and economic assumptions were utilized in the economic model analysis.

| | |
|---|---|
| • Capital Costs | Table 4-2 |
| • Heat Rate Performance Assumptions | Table 4-2 |
| • Emissions | Table 4-3 |
| • Fuel Cost Forecast | Table 5-1 |
| • Purchased Wind Cost | \$50/MWh held constant |
| • O&M Cost Assumptions: | |
| Fixed O&M Costs | Table 4-2 |
| Insurance | 0.05% of Capital Cost per year |
| Property Taxes | 0.5% of Capital Cost per year |
| Variable O&M Costs | Table 4-2 |
| Transmission Costs | Not Included – Busbar Cost Evaluation |
| Emissions Allowance Costs | \$700/ton $SO_2$<br>\$1,300/ton $NO_x$ (ozone season)<br>\$35,000/lb Mercury |
| • Operating Assumptions: | |
| Overall Capacity Factor | 88.0% for baseload comparison |

## 5.3 FUEL COST FORECAST

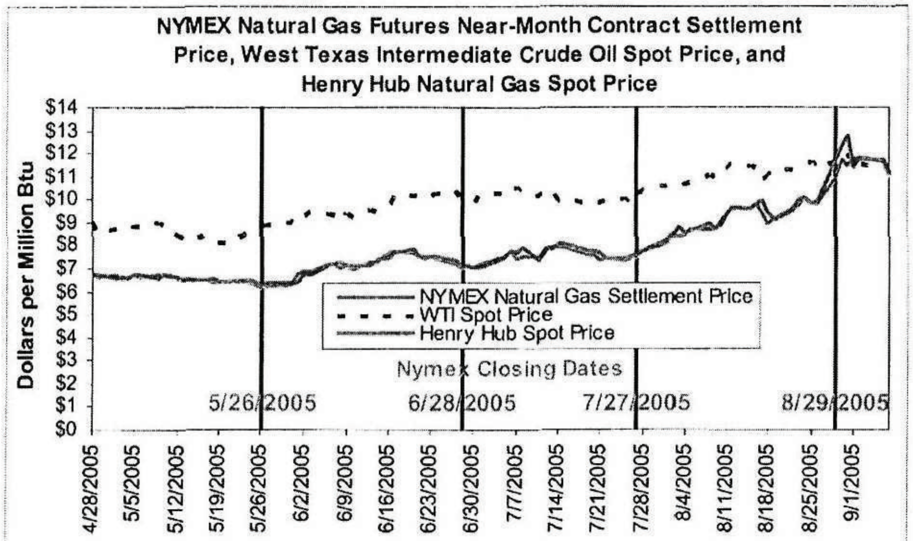
Table 5-1 presents the base case fuel cost assumptions used in the economic model analysis for each of the baseload technology alternatives. Detailed fuel cost forecasts are provided in Table 5-2.

Table 5-1: Base Case Fuel Cost Assumptions

| Technology | Fuel | Delivered Cost Estimate | Escalation |
|---|---|---|---|
| PC Units | PRB Coal | $1.21/MMBtu (2007$) | 2.0% |
| IGCC Unit | ILB Coal | $2.47/MMBtu (2007$) | 2.0% |
| CCGT Unit | Natural Gas | $7.00/MMBtu (2011$) | 2.5% |
| Biomass Unit | Wood Crop | $5.98/MMBtu (2007$) | 2.0% |

Note that the natural gas cost forecast of $7.00/MMBtu for 2011 is significantly lower than current 2005 natural gas cost pricing. Natural gas prices in 2005 have increased to near-record levels in the aftermath of Hurricane Katrina as exhibited in Figure 5-1. It is difficult to predict if natural gas prices will decline back to the $7.00/MMBtu level, but the economic analysis is based on this assumption, and sensitivity analyses have been prepared with high and low natural gas cost cases. Figure 5-2 illustrates the near-term futures market for natural gas through 2010, which remains above $7.00/MMBtu on a commodity basis for the foreseeable future.

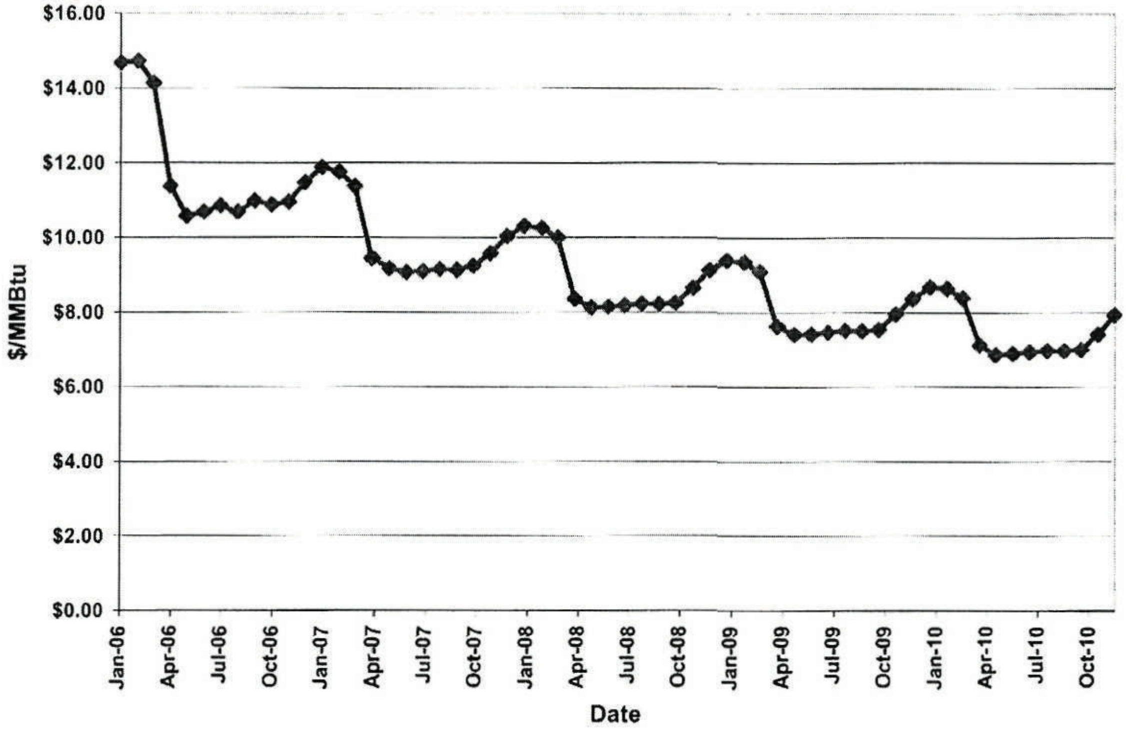
Figure 5-1: 2005 Natural Gas Prices



Note:The West Texas Intermediate crude oil price, in dollars per barrel, is converted to $/MMBtu using a conversion factor of 5.80 MMBtu per barrel. The dates marked by vertical lines are the NYMEX near-month contract settlement dates.

Source: NGI's *Daily Gas Price Index* (http://intelligencepress.com)

Figure 5-2: Near-term Futures Market for Natural Gas (Henry Hub)



Source: New York Mercantile Exchange

Table 5-2: Delivered Fuel Costs

($/MMBtu)

| | | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **PRB Coal** | Commodity | $ 0.51 | $ 0.52 | $ 0.53 | $ 0.54 | $ 0.55 | $ 0.56 | $ 0.57 | $ 0.58 | $ 0.60 | $ 0.61 | $ 0.62 | $ 0.63 |
| | Transporation | $ 0.70 | $ 0.71 | $ 0.73 | $ 0.74 | $ 0.76 | $ 0.77 | $ 0.79 | $ 0.80 | $ 0.82 | $ 0.84 | $ 0.85 | $ 0.87 |
| | **Delivered** | **$ 1.21** | **$ 1.23** | **$ 1.26** | **$ 1.28** | **$ 1.31** | **$ 1.33** | **$ 1.36** | **$ 1.39** | **$ 1.42** | **$ 1.44** | **$ 1.47** | **$ 1.50** |
| **ILB Coal** | Commodity | $ 1.49 | $ 1.52 | $ 1.55 | $ 1.58 | $ 1.62 | $ 1.65 | $ 1.68 | $ 1.71 | $ 1.75 | $ 1.78 | $ 1.82 | $ 1.86 |
| | Transporation | $ 0.79 | $ 0.81 | $ 0.82 | $ 0.84 | $ 0.86 | $ 0.87 | $ 0.89 | $ 0.91 | $ 0.93 | $ 0.94 | $ 0.96 | $ 0.98 |
| | **Delivered** | **$ 2.28** | **$ 2.33** | **$ 2.37** | **$ 2.42** | **$ 2.47** | **$ 2.52** | **$ 2.57** | **$ 2.62** | **$ 2.67** | **$ 2.73** | **$ 2.78** | **$ 2.84** |
| **Natural Gas** | Commodity | $ 9.88 | $ 8.79 | $ 8.02 | $ 7.45 | $ 6.60 | $ 6.77 | $ 6.93 | $ 7.11 | $ 7.29 | $ 7.47 | $ 7.65 | $ 7.85 |
| | Transporation | $ 0.40 | $ 0.40 | $ 0.40 | $ 0.40 | $ 0.40 | $ 0.41 | $ 0.42 | $ 0.43 | $ 0.44 | $ 0.45 | $ 0.46 | $ 0.48 |
| | **Delivered** | **$ 10.28** | **$ 9.19** | **$ 8.42** | **$ 7.85** | **$ 7.00** | **$ 7.18** | **$ 7.35** | **$ 7.54** | **$ 7.73** | **$ 7.92** | **$ 8.12** | **$ 8.32** |
| **Dedicated Biomass** | Commodity | $4.79 | $ 4.88 | $ 4.98 | $ 5.08 | $ 5.18 | $ 5.28 | $ 5.39 | $ 5.50 | $ 5.61 | $ 5.72 | $ 5.83 | $ 5.95 |
| | Transporation | $1.20 | $ 1.22 | $ 1.24 | $ 1.27 | $ 1.30 | $ 1.32 | $ 1.35 | $ 1.37 | $ 1.40 | $ 1.43 | $ 1.46 | $ 1.49 |
| | **Delivered** | **$ 5.98** | **$ 6.10** | **$ 6.22** | **$ 6.35** | **$ 6.48** | **$ 6.60** | **$ 6.74** | **$ 6.87** | **$ 7.01** | **$ 7.15** | **$ 7.29** | **$ 7.44** |

| | | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **PRB Coal** | Commodity | $ 0.64 | $ 0.66 | $ 0.67 | $ 0.68 | $ 0.70 | $ 0.71 | $ 0.73 | $ 0.74 | $ 0.76 | $ 0.77 | $ 0.79 | $ 0.80 |
| | Transporation | $ 0.89 | $ 0.91 | $ 0.92 | $ 0.94 | $ 0.96 | $ 0.98 | $ 1.00 | $ 1.02 | $ 1.04 | $ 1.06 | $ 1.08 | $ 1.10 |
| | **Delivered** | **$ 1.53** | **$ 1.56** | **$ 1.59** | **$ 1.63** | **$ 1.66** | **$ 1.69** | **$ 1.73** | **$ 1.76** | **$ 1.80** | **$ 1.83** | **$ 1.87** | **$ 1.91** |
| **ILB Coal** | Commodity | $ 1.89 | $ 1.93 | $ 1.97 | $ 2.01 | $ 2.05 | $ 2.09 | $ 2.13 | $ 2.17 | $ 2.22 | $ 2.26 | $ 2.31 | $ 2.35 |
| | Transporation | $ 1.00 | $ 1.02 | $ 1.04 | $ 1.06 | $ 1.08 | $ 1.11 | $ 1.13 | $ 1.15 | $ 1.17 | $ 1.20 | $ 1.22 | $ 1.25 |
| | **Delivered** | **$ 2.89** | **$ 2.95** | **$ 3.01** | **$ 3.07** | **$ 3.13** | **$ 3.20** | **$ 3.26** | **$ 3.32** | **$ 3.39** | **$ 3.46** | **$ 3.53** | **$ 3.60** |
| **Natural Gas** | Commodity | $ 8.04 | $ 8.24 | $ 8.45 | $ 8.66 | $ 8.88 | $ 9.10 | $ 9.33 | $ 9.56 | $ 9.80 | $ 10.04 | $ 10.29 | $ 10.55 |
| | Transporation | $ 0.49 | $ 0.50 | $ 0.51 | $ 0.52 | $ 0.54 | $ 0.55 | $ 0.57 | $ 0.58 | $ 0.59 | $ 0.61 | $ 0.62 | $ 0.64 |
| | **Delivered** | **$ 8.53** | **$ 8.74** | **$ 8.96** | **$ 9.18** | **$ 9.41** | **$ 9.65** | **$ 9.89** | **$ 10.14** | **$ 10.39** | **$ 10.65** | **$ 10.92** | **$ 11.19** |
| **Dedicated Biomass** | Commodity | $ 6.07 | $ 6.19 | $ 6.31 | $ 6.44 | $ 6.57 | $ 6.70 | $ 6.84 | $ 6.97 | $ 7.11 | $ 7.25 | $ 7.40 | $ 7.55 |
| | Transporation | $ 1.52 | $ 1.55 | $ 1.58 | $ 1.61 | $ 1.64 | $ 1.68 | $ 1.71 | $ 1.74 | $ 1.78 | $ 1.81 | $ 1.85 | $ 1.89 |
| | **Delivered** | **$ 7.59** | **$ 7.74** | **$ 7.89** | **$ 8.05** | **$ 8.21** | **$ 8.38** | **$ 8.54** | **$ 8.72** | **$ 8.89** | **$ 9.07** | **$ 9.25** | **$ 9.43** |

## 5.4 FINANCING AND ECONOMIC ASSUMPTIONS

The following financing and economic assumptions were utilized in the economic model analysis. The economic model analyses were prepared under two distinct ownership and cost of capital structures: investor owned utility and public power utility. Of the seven participating utilities, OTPCo and MDU are investor owned utilities. CMMPA, GRE, MRES, HCPD and SMMPA are public power utilities. Note that each of the seven participating utilities will have its own financing plan, capital structure, rate of return, tax rate, and depreciation schedule for its share of the BSPII Project, and the specific cost of capital assumptions will vary. The following assumptions are used to represent the relative difference in capital cost financing for the different ownership structures.

- Financing Assumptions (Investor Owned Utility):

| | |
|---|---|
| Interest Rate | 7.5% |
| Term | 20 years |
| Debt/Equity Percentage | 50%/50% |
| Return on Equity | 12.0% |
| Construction Financing Fees | 0.50% |
| Permanent Financing Fees | 1.00% |
| Construction Financing | 48 months for PC and IGCC<br>30 months for Biomass<br>24 months for CCGT |

- Financing Assumptions (Public Power):

| | |
|---|---|
| Interest Rate | 6.0% |
| Term | 30 years |
| Debt/Equity Percentage | 100%/0% |
| Return on Equity | N/A |
| Construction Financing Fees | 0.50% |
| Permanent Financing Fees | 1.00% |
| Construction Financing | 48 months for PC and IGCC<br>30 months for Biomass<br>24 months for CCGT |

- Economic Assumptions:

| | |
|---|---|
| O&M Inflation | 2.5% per annum |
| Construction Cost Inflation | 2.5% per annum |
| Solid Fuel Inflation | Included in forecast |
| Solid Fuel Transportation Inflation | Included in forecast |
| Discount Rate (Investor Owned Utility) | 9.75% |
| Discount Rate (Public Power) | 6.0% |
| Effective Tax Rate (IOU only) | 40.0% |
| Book Depreciation | 30 years |
| Tax Depreciation (IOU only) | 20 years |

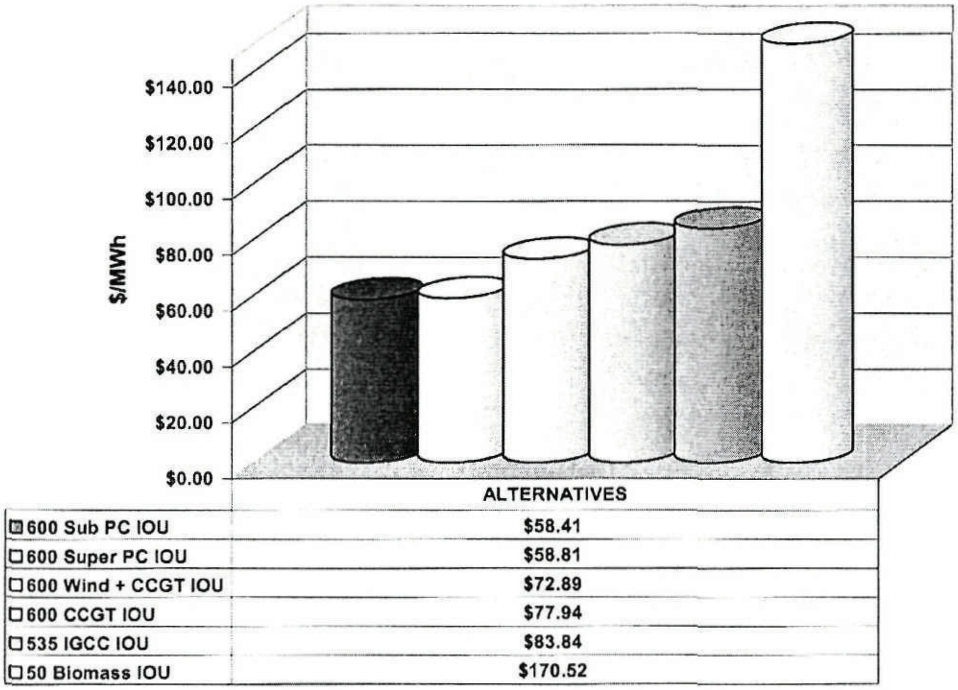
Note that the capital cost estimates presented in Table 4-2 are escalated to the midpoint of construction. The O&M estimates in Table 4-2 are presented in 2005 dollars.

## 5.5 ECONOMIC ANALYSIS RESULTS

The economic model analyses were used to determine the busbar cost of power for each alternative.

Figure 5-3 presents a graph of the resulting levelized busbar power costs for each of the baseload generation alternatives for an investor owned utility. Figure 5-3 was developed by preparing a project economic model for each of the alternatives under consideration. The busbar cost represents the levelized all-in energy cost in 2011$ for a 20 year planning period. Figure 5-4 presents the annual busbar cost for each of the baseload generation alternatives over 20 years for an investor owned utility ownership structure.

Figure 5-3: Levelized Busbar Costs (2011$) – Investor Owned Utility



| | ALTERNATIVES |
|---|---|
| ▨ 600 Sub PC IOU | $58.41 |
| ☐ 600 Super PC IOU | $58.81 |
| ☐ 600 Wind + CCGT IOU | $72.89 |
| ☐ 600 CCGT IOU | $77.94 |
| ☐ 535 IGCC IOU | $83.84 |
| ☐ 50 Biomass IOU | $170.52 |

Figure 5-4: Annual Busbar Costs – Investor Owned Utility

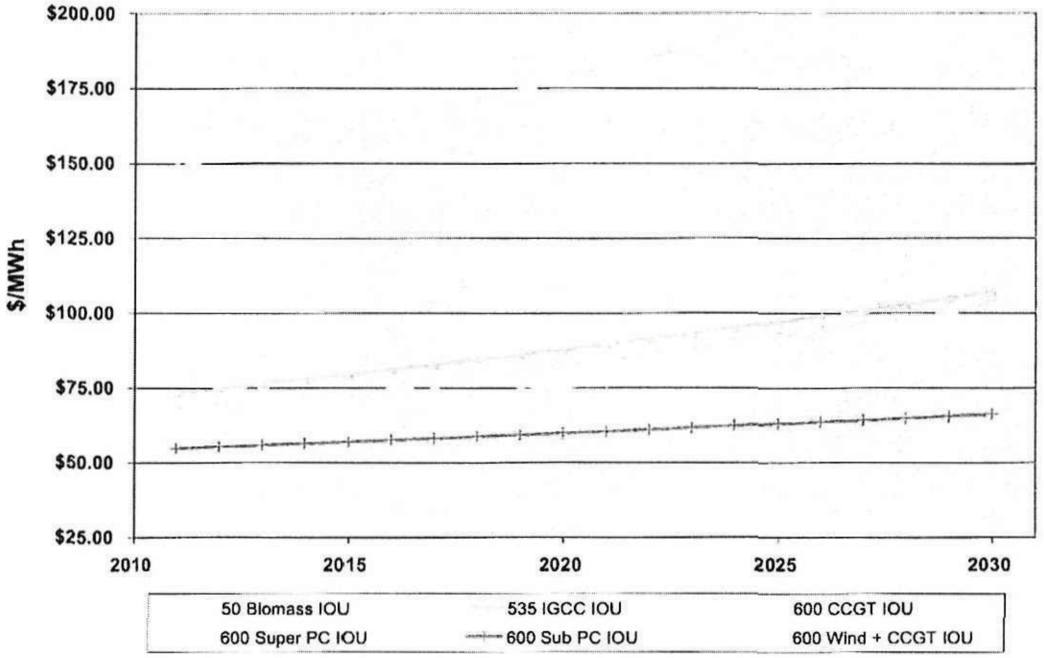
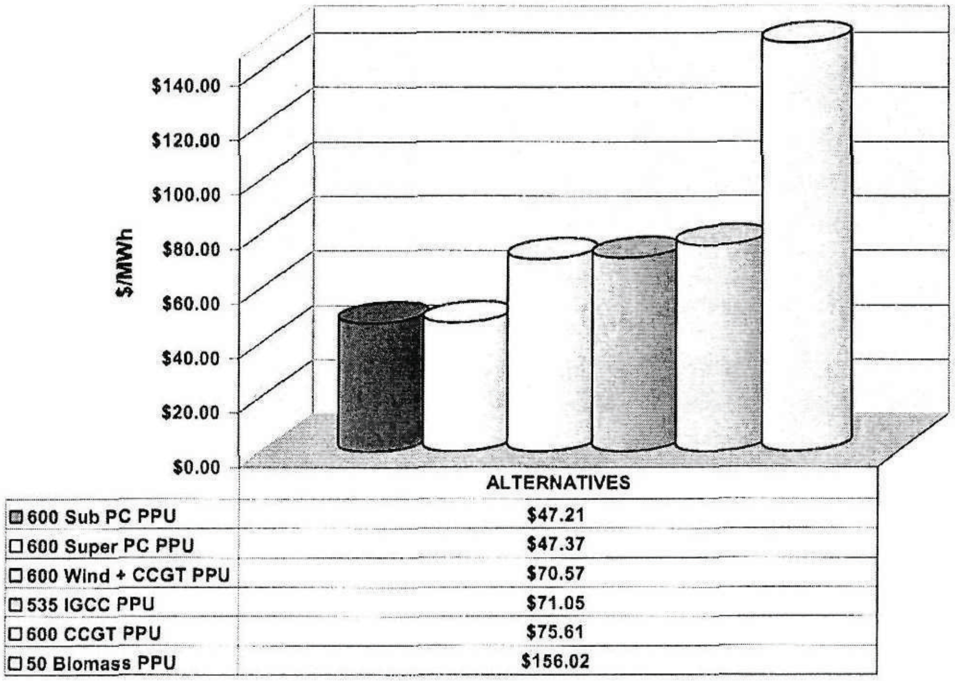


Figure 5-5 presents a graph of the resulting levelized busbar power costs for each of the baseload generation alternatives for a public power utility. Figure 5-5 was developed by preparing a project economic model for each of the alternatives under consideration. The busbar cost represents the levelized all-in energy cost in 2011$ for a 20 year planning period. Figure 5-6 presents the annual busbar cost for each of the baseload generation alternatives over 20 years for public power utility ownership structure

Figure 5-5: Levelized Busbar Costs (2011$) – Public Power



| | ALTERNATIVES |
|---|---|
| ▨ 600 Sub PC PPU | $47.21 |
| ☐ 600 Super PC PPU | $47.37 |
| ☐ 600 Wind + CCGT PPU | $70.57 |
| ☐ 535 IGCC PPU | $71.05 |
| ☐ 600 CCGT PPU | $75.61 |
| ☐ 50 Biomass PPU | $156.02 |

Figure 5-6: Annual Busbar Costs – Public Power

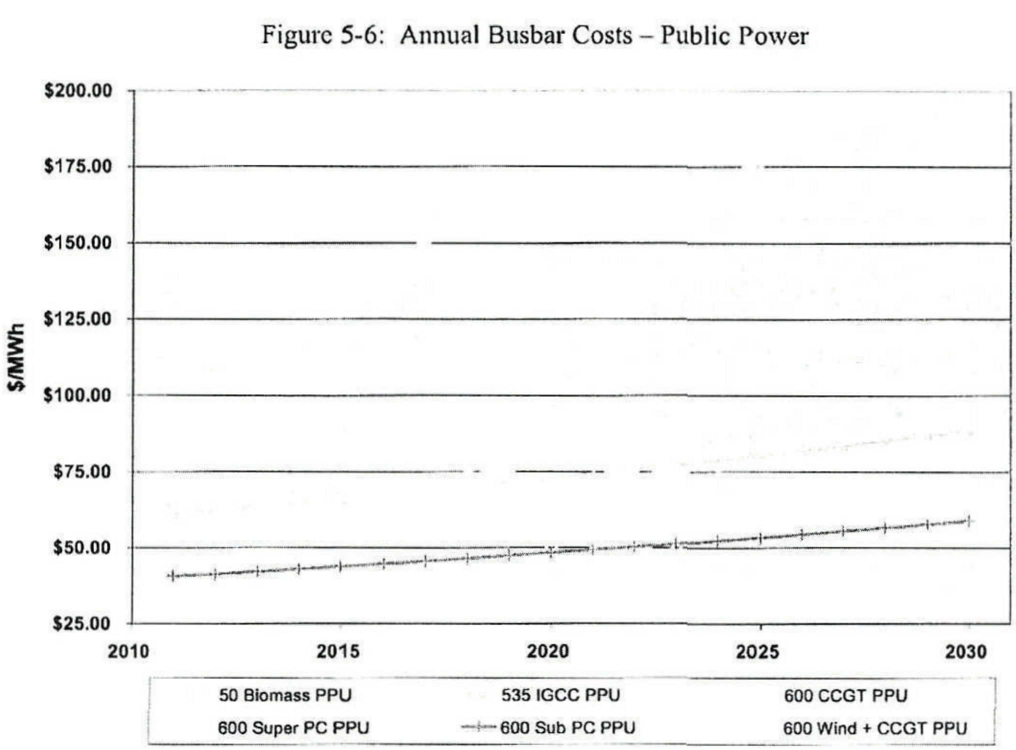


Table 5-3 provides the annual busbar cost for the first twenty years of operations for both an investor owned utility and a public power utility for each alternative.

## 5.6 ECONOMIC CONCLUSIONS

As indicated in Figures 5-3 and 5-5, the PC unit alternatives represent significantly lower cost baseload alternatives for the participating utilities and their customers. The coal-fired options are preferred to the combined cycle plant, wind plus combined cycle plant, IGCC plant and Biomass plant for baseload energy production. The higher construction costs of the IGCC and Biomass plants along with the higher fuel costs make them uneconomical in comparison to the PC unit alternatives, by significant margins. In addition, the IGCC technology should be considered a developing technology, and IGCC plants in the United States have not achieved high capacity factor operations with any consistency.

Although the combined cycle plant has lower capital costs, the high natural gas fuel cost, even under a natural gas cost forecast of $7.00/MMBtu for 2011, makes it uneconomical for baseload dispatch. The wind plus CCGT plant reflects the next lowest cost baseload resource choice, but is 24 percent higher cost for the IOU utilities and 49 percent higher cost for the public power utilities compared to the PC alternatives for baseload energy production.

The overall economic difference between subcritical and supercritical PC technology is not material. The subcritical PC unit is marginally more economically attractive than a supercritical PC unit, but for purposes of this Study would be considered economically equivalent. The proposed BSPII Project will utilize supercritical PC technology in order to reduce total annual emissions. Although the emissions rates are equivalent on a lb/MMBtu basis, the increased efficiency of a supercritical unit will result in lower emissions than a subcritical unit due to lower fuel consumption. Also, this increased efficiency offsets the slightly higher capital cost of a supercritical unit.

The 50 MW biomass plant is not economically viable for baseload energy production. A lower cost renewable option would be to co-fire a percentage of the heat input of the 600 MW BSPII Project with a wood residue, wood crop, or agricultural waste. A five percent co-fire on a heat input basis would represent the equivalent of a 30 MW biomass plant.

Table 5-3: Annual Busbar Cost

($/MWh)

| | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Investor Owned Utility | 600 MW Super PC | $55.01 | $55.56 | $56.11 | $56.67 | $57.24 | $57.81 | $58.39 | $58.97 | $59.56 | $60.16 | $60.76 | $61.37 | $61.98 | $62.60 | $63.23 | $63.86 | $64.50 | $65.14 | $65.79 | $66.45 |
| | 600 MW Sub PC | $54.63 | $55.18 | $55.73 | $56.29 | $56.85 | $57.42 | $57.99 | $58.57 | $59.16 | $59.75 | $60.35 | $60.95 | $61.56 | $62.18 | $62.80 | $63.43 | $64.06 | $64.70 | $65.35 | $66.00 |
| | 600 MW CCGT + Wind | $65.63 | $66.61 | $67.62 | $68.65 | $69.70 | $70.77 | $71.88 | $73.00 | $74.15 | $75.33 | $76.53 | $77.77 | $79.03 | $80.32 | $81.63 | $82.98 | $84.36 | $85.78 | $87.22 | $88.70 |
| | 600 MW CCGT | $66.67 | $68.19 | $69.75 | $71.35 | $72.99 | $74.66 | $76.37 | $78.12 | $79.90 | $81.73 | $83.61 | $85.52 | $87.48 | $89.48 | $91.53 | $93.63 | $95.77 | $97.97 | $100.21 | $102.50 |
| | 535 MW IGCC | $73.19 | $74.66 | $76.15 | $77.67 | $79.22 | $80.81 | $82.43 | $84.07 | $85.76 | $87.47 | $89.22 | $91.00 | $92.82 | $94.68 | $96.57 | $98.51 | $100.48 | $102.49 | $104.54 | $106.63 |
| | 50 MW Biomass | $148.87 | $151.85 | $154.88 | $157.98 | $161.14 | $164.36 | $167.65 | $171.00 | $174.42 | $177.91 | $181.47 | $185.10 | $188.80 | $192.58 | $196.43 | $200.36 | $204.37 | $208.45 | $212.62 | $216.87 |
| Public Power Utility | 600 MW Super PC | $40.50 | $41.31 | $42.14 | $42.98 | $43.84 | $44.71 | $45.61 | $46.52 | $47.45 | $48.40 | $49.37 | $50.36 | $51.36 | $52.39 | $53.44 | $54.51 | $55.60 | $56.71 | $57.84 | $59.00 |
| | 600 MW Sub PC | $40.36 | $41.17 | $41.99 | $42.83 | $43.69 | $44.56 | $45.45 | $46.36 | $47.29 | $48.24 | $49.20 | $50.18 | $51.19 | $52.21 | $53.26 | $54.32 | $55.41 | $56.52 | $57.65 | $58.80 |
| | 600 MW CCGT + Wind | $62.68 | $63.60 | $64.53 | $65.49 | $66.47 | $67.47 | $68.49 | $69.54 | $70.61 | $71.71 | $72.83 | $73.98 | $75.15 | $76.35 | $77.58 | $78.84 | $80.12 | $81.44 | $82.78 | $84.16 |
| | 600 MW CCGT | $63.14 | $64.58 | $66.06 | $67.57 | $69.12 | $70.71 | $72.32 | $73.98 | $75.67 | $77.41 | $79.18 | $80.99 | $82.85 | $84.75 | $86.69 | $88.67 | $90.70 | $92.78 | $94.90 | $97.08 |
| | 535 MW IGCC | $60.74 | $61.96 | $63.20 | $64.46 | $65.75 | $67.06 | $68.41 | $69.77 | $71.17 | $72.59 | $74.04 | $75.53 | $77.04 | $78.58 | $80.15 | $81.75 | $83.39 | $85.05 | $86.75 | $88.49 |
| | 50 MW Biomass | $133.38 | $136.05 | $138.77 | $141.54 | $144.38 | $147.26 | $150.21 | $153.21 | $156.28 | $159.40 | $162.59 | $165.84 | $169.16 | $172.54 | $175.99 | $179.51 | $183.11 | $186.77 | $190.50 | $194.31 |

## 5.7 SENSITIVITY ANALYSIS AND RESULTS

A sensitivity analysis was prepared for each of the baseload generation technology alternatives for both the investor owned utility and public power ownership structures under the following cases:

| | |
|---|---|
| • Capital Cost | (plus or minus 10%) |
| • Interest Rate | (plus or minus one (1) percentage point) |
| • Capacity Factor | (plus or minus 5%) |
| • Fuel Cost | (plus or minus 10%) |
| • O&M Costs | (plus or minus 10%) |
| • Wind Energy Purchase Cost | (plus or minus 10%) |

The results of the sensitivity analyses are presented in tornado diagrams in Figures 5-7, 5-8, 5-9, 5-10, 5-11, and 5-12 for the 600 MW supercritical PC alternative, the 600 MW wind plus CCGT alternative, and the 600 MW CCGT alternative. A tornado diagram illustrates the range of results for each sensitivity case and its impact on the levelized power cost, and ranks the results from greatest impact to least impact. The sensitivity analysis indicates that capital cost and capacity factor are the two most significant factors affecting the economics of a coal-fired unit for an investor owned utility. For a public power utility, the interest rate and capital cost are the most significant factors affecting the economics of a coal-fired unit. Delivered fuel cost by far has the strongest impact on the overall economics of the combined cycle unit alternatives, both with and without wind turbines. This is an important result since the market price of natural gas is inherently volatile and nearly impossible for a utility to control over a 20 year planning period. Additionally, the cost of purchasing wind power for the 600 MW CCGT plus wind alternative has a large impact on the total economics of the Project.

Figure 5-7: Tornado Diagram – 600 MW Supercritical Unit, Investor Owned Utility

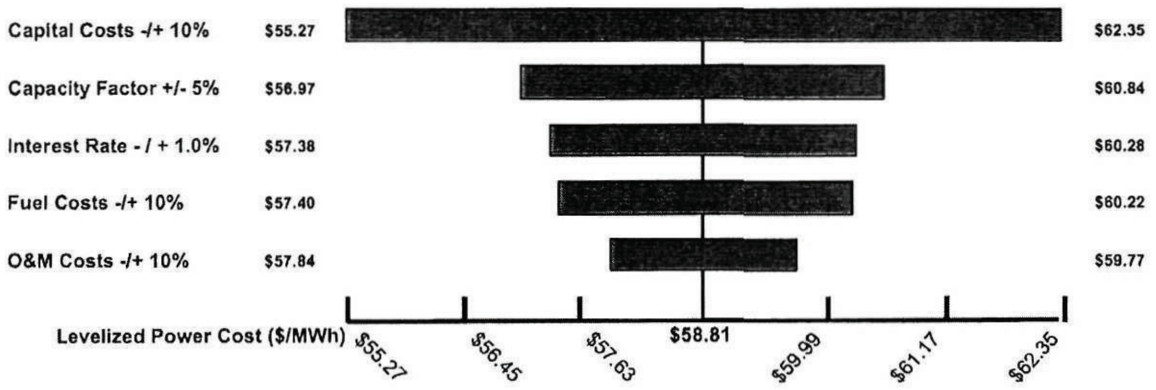


Figure 5-8: Tornado Diagram – 600 MW Wind Plus CCGT, Investor Owned Utility

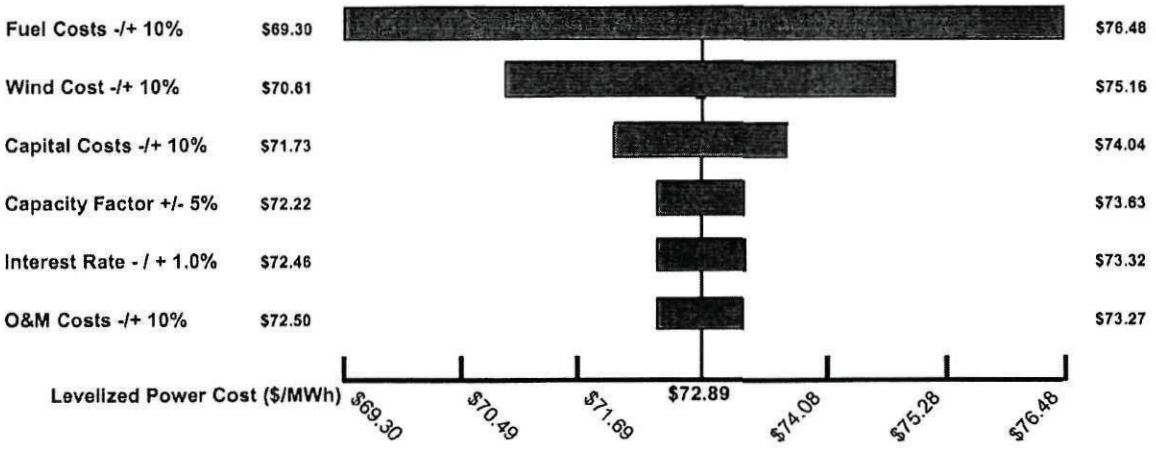


Figure 5-9: Tornado Diagram – 600 MW CCGT, Investor Owned Utility

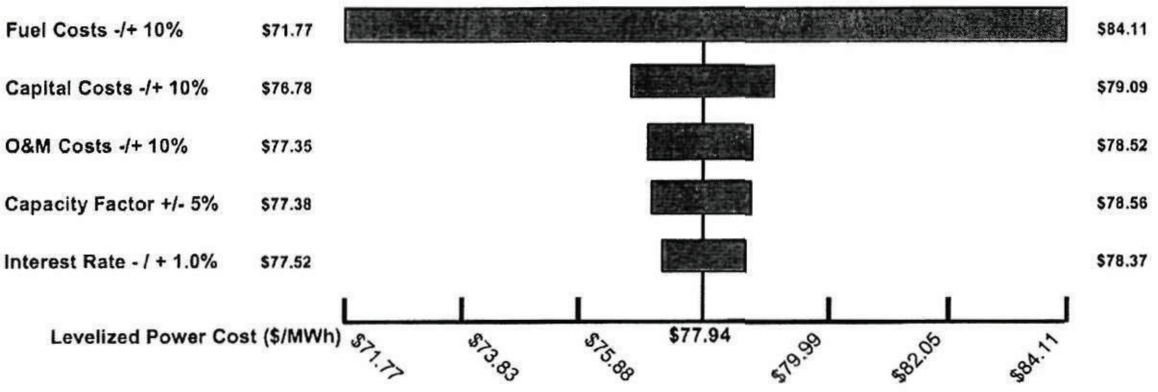


Figure 5-10: Tornado Diagram – 600 MW Supercritical Unit, Public Power

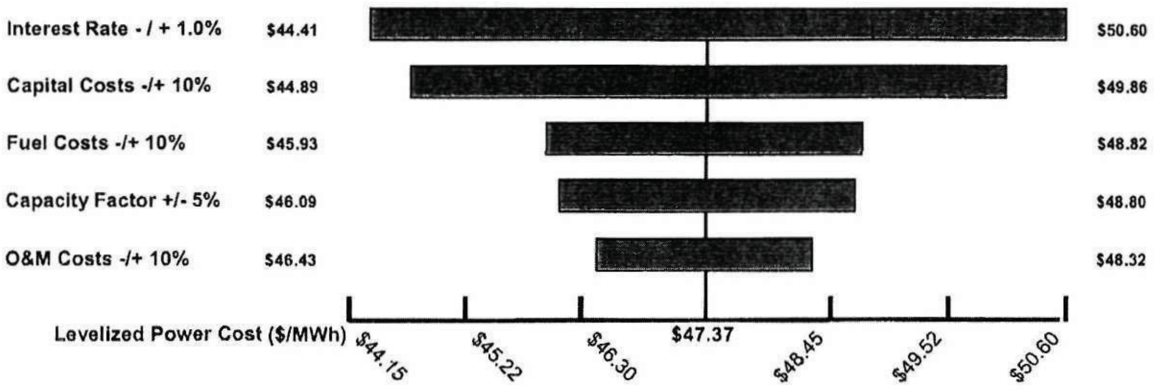


Figure 5-11: Tornado Diagram – 600 MW Wind Plus CCGT, Public Power

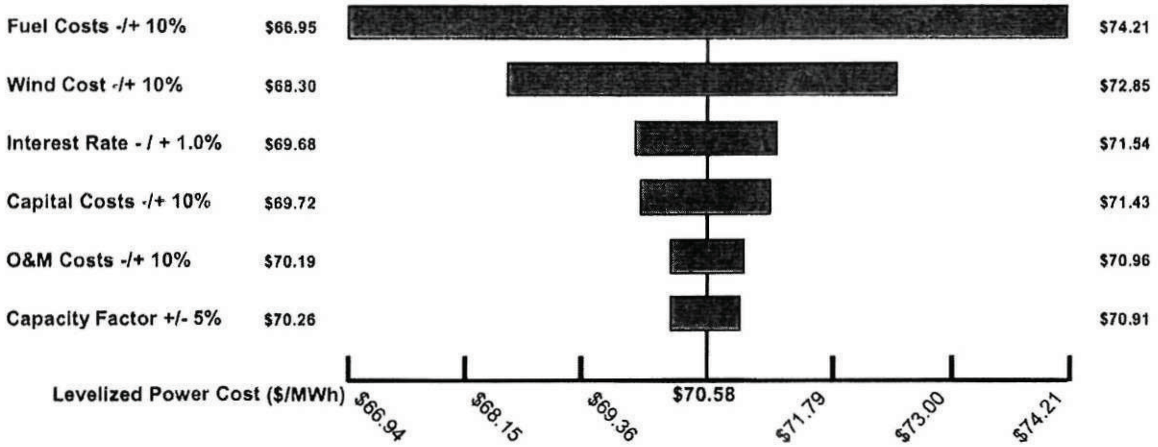
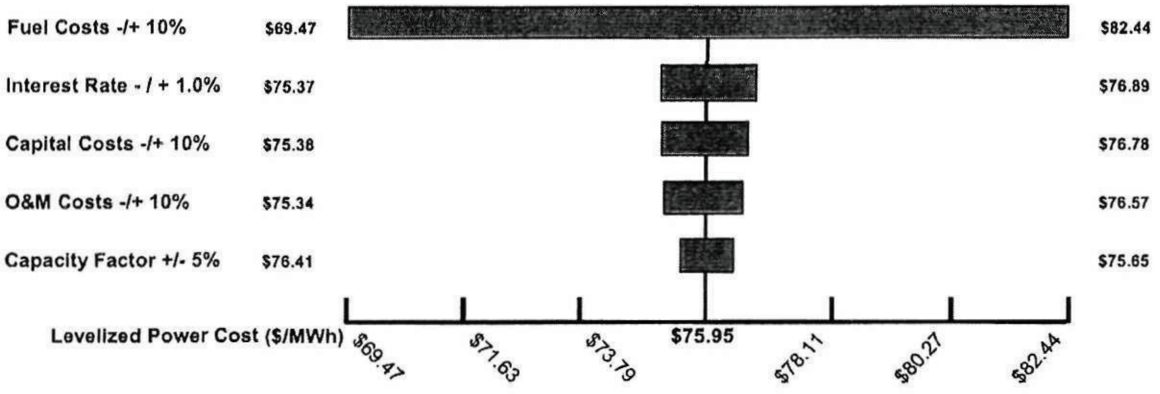


Figure 5-12: Tornado Diagram – 600 MW CCGT, Public Power



Coal-fired generation resources are more capital intensive than natural gas combined cycle plants, and have a construction period that can be more than twice the length of a combined cycle plant. This results in more capital risk due to interest costs, labor availability and costs, and general inflation. The primary tradeoff for these higher capital risks with a solid fuel generation resource is the long-term stability of coal which has few competing uses relative to natural gas that is used by almost all economic sectors including residential heating.

The economics of coal-fired generation for baseload energy production are robust for the different sensitivity analyses. The high capital cost sensitivity for the supercritical PC alternative resulted in an increase in the levelized busbar cost of $3.54/MWh and $3.23/MWh for the IOU and public power utilities, respectively. The high fuel cost sensitivity for the wind plus CCGT alternative resulted in an increase in the levelized busbar cost of $3.59/MWh and $3.63/MWh for the IOU and public power utilities, respectively. As indicated, long-term natural gas costs would also be expected to be much more volatile than short-term construction costs.

## 5.8 PTC SENSITIVITY

The estimated purchase cost of $50/MWh for wind resources is based on a 2011 commercial operation date. As such, it does not include the current Renewable Energy PTC that was extended to December 31, 2007 for wind resources in the Energy Policy Act of 2005. The current PTC for wind energy is 1.9 cents/kWh. A sensitivity analysis was prepared assuming that the PTC is further extended or replaced with a similar tax credit. In the sensitivity analysis, the estimated levelized purchase cost of wind energy was reduced to $38/MWh for the 600 MW wind plus combined cycle case.

For the investor-owned utilities, assuming a PTC is re-established lowers the levelized busbar cost of the 600 MW wind plus CCGT case to $67.43/MWh. This cost is 15 percent higher than the base case supercritical PC unit cost of $58.81/MWh. For the public power utilities, assuming a PTC is re-established lowers the levelized busbar cost of the 600 MW wind plus CCGT case to $65.12/MWh. This cost is 37 percent higher than the base case supercritical PC unit cost of $47.37/MWh. The inclusion of a PTC for wind energy does not change the relative economics of the baseload generation resource choice.

# Section 6

# Carbon Tax Scenarios

# 6.0 CARBON TAX SCENARIOS

## 6.1 OBJECTIVE

B&McD evaluated the impact of a potential carbon tax on the decision to develop and construct the 600 MW supercritical PC unit at the Big Stone site to meet the baseload energy requirements of the participating utilities.

## 6.2 IMPACT OF A CARBON TAX ON A NEW BASELOAD UNIT

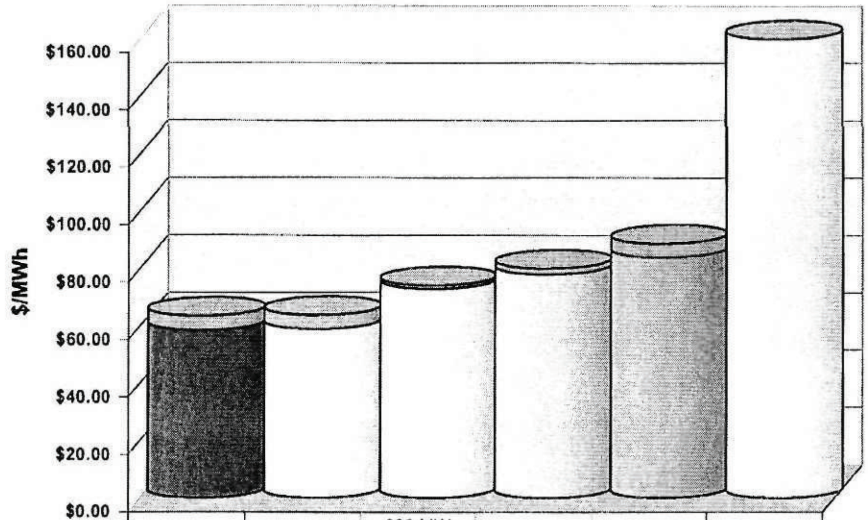
The emissions costs of the different baseload generation alternatives have been internalized in the economic model analysis. Each baseload generation alternative includes control technologies to meet expected BACT requirements, and emission allowance costs are incorporated for $NO_x$ (ozone season), $SO_2$, and mercury.

The Minnesota Public Utilities Commission has identified a range of values for a carbon dioxide externality of $0.35/ton to $3.64/ton for a power plant located in Minnesota. The carbon dioxide externality value for a power plant located in South Dakota is zero. The inclusion of a carbon dioxide externality value, or imposition of a carbon tax, would cause an increase in the busbar cost of power for a new baseload resource. Figures 6-1 and 6-2 below present the impact of the $3.64/ton $CO_2$ externality value on the economic modeling results under both investor owned utilities and public power utilities.

The estimated carbon dioxide emissions of each of the baseload technologies are listed below:

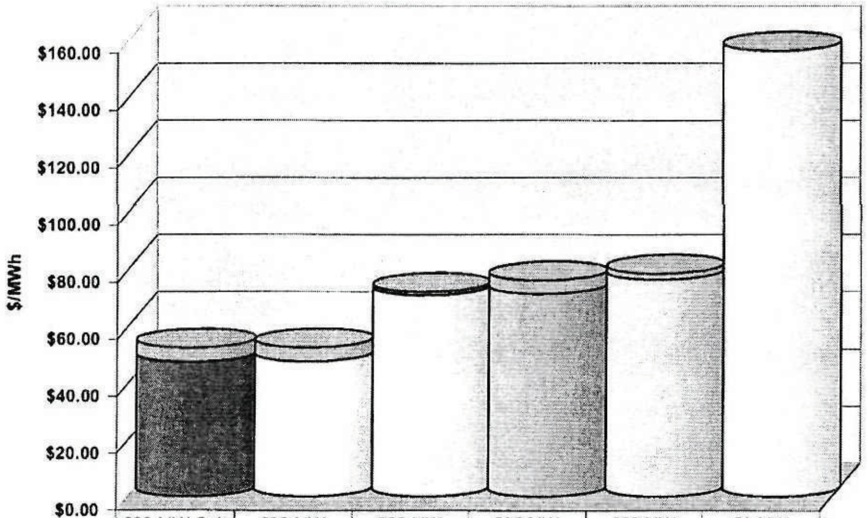
| | |
|---|---|
| • PC Units | 208 lbs/MMBtu |
| • CCGT Unit | 110 lbs/MMBtu |
| • Wind Plus CCGT Unit | 110 lbs/MMBut gas, 0 lbs/MMBtu wind |
| • IGCC Unit | 200 lbs/MMBtu (capture and sequestration not included) |
| • Biomass Unit | 0 lbs/MMBtu (assumes closed-loop system) |

Figure 6-1: Levelized Busbar Costs – Investor Owned Utility – $CO_2$ Externality



| | 600 MW Sub PC | 600 MW Super PC | 600 MW CCGT + Wind | 600 MW CCGT | 535 MW IGCC | 50 MW Biomass |
|---|---|---|---|---|---|---|
| Total Busbar Cost | $63.39 | $63.69 | $74.08 | $79.98 | $88.67 | $170.52 |
| □ Carbon Tax | $4.98 | $4.88 | $1.19 | $2.04 | $4.83 | $0.00 |
| ▨ Busbar Cost w/o Carbon Tax | $58.41 | $58.81 | $72.89 | $77.94 | $83.84 | $170.52 |

Figure 6-2: Levelized Busbar Costs – Public Power – $CO_2$ Externality



| | 600 MW Sub PC | 600 MW Super PC | 600 MW CCGT + Wind | 535 MW IGCC | 600 MW CCGT | 50 MW Biomass |
|---|---|---|---|---|---|---|
| Total Busbar Cost | $52.16 | $52.22 | $71.77 | $75.81 | $78.10 | $156.02 |
| □ Carbon Tax | $4.94 | $4.84 | $1.20 | $4.76 | $2.14 | $0.00 |
| ▨ Busbar Cost w/o Carbon Tax | $47.21 | $47.37 | $70.57 | $71.05 | $75.96 | $156.02 |

As indicated in Figures 6-1 and 6-2, the inclusion of a carbon externality or tax of $3.64/ton increases the levelized busbar costs of all the alternatives, but does not change the relative economics of the baseload generation resource choice.

The break-even carbon dioxide externality value to equalize the 600 MW supercritical PC unit levelized busbar cost with the 600 MW wind plus CCGT levelized busbar cost is approximately $14.00/ton in 2011 for the investor owned utility ownership structure. This would increase the levelized busbar cost of both alternatives to $77/MWh, which is an increase of 31 percent compared to the base case supercritical PC unit cost of $58.81/MWh.

The break-even carbon dioxide externality value to equalize the 600 MW supercritical PC unit levelized busbar cost with the 600 MW wind plus CCGT levelized busbar cost is approximately $23.00/ton in 2011 for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to $78/MWh, which is an increase of 65 percent compared to the base case supercritical PC unit cost of $47.37/MWh.

## 6.3 PTC AND CARBON TAX SENSITIVITY

A sensitivity analysis was prepared under a carbon tax scenario, assuming that the 1.9 cents/kWh PTC is further extended or replaced with a similar tax credit. In the sensitivity analysis, the estimated levelized purchase cost of wind energy was reduced to $38/MWh for the 600 MW wind plus combined cycle case.

### 6.3.1 Investor-Owned Utility PTC and Carbon Tax Sensitivity Results

For the investor-owned utilities, assuming a PTC is re-established results in a levelized busbar cost of $68.62/MWh for the 600 MW wind plus CCGT case including a carbon externality or tax of $3.64/ton. This cost is 8 percent higher than the supercritical PC unit cost of $63.69/MWh. The inclusion of a PTC for wind energy and the inclusion of a carbon externality or tax of $3.64/ton does not change the relative economics of the baseload generation resource choice. The break-even carbon dioxide externality value to equalize the 600 MW supercritical PC unit levelized busbar cost with the 600 MW wind plus CCGT levelized busbar cost is approximately $8.50/ton in 2011 for the investor owned utility ownership structure if a 1.9 cents/kWh PTC is included for the wind energy component.

### 6.3.2 Public Power Utility PTC and Carbon Tax Sensitivity Results

For the public power utilities, assuming a PTC is re-established results in a levelized busbar cost of $66.33/MWh for the 600 MW wind plus CCGT case including a carbon externality or tax of $3.64/ton. This cost is 27 percent higher than the supercritical PC unit cost of $52.22/MWh. The inclusion of a PTC for wind energy and the inclusion of a carbon externality or tax of $3.64/ton does not change the relative economics of the baseload generation resource choice. The break-even carbon dioxide externality value to equalize the 600 MW supercritical PC unit levelized busbar cost with the 600 MW wind plus CCGT levelized busbar cost is approximately $17.75/ton in 2011 for the public power ownership structure if a 1.9 cents/kWh PTC is included for the wind energy component.

## 6.4 OVERVIEW

Overall, inclusion of a carbon externality value or carbon tax in the evaluation would not impact the baseload generation resource decision unless a significant tax or other cost was imposed.

# Case No. PU-06-482
# Exhibit No.___(MR-2)

# Revised Analysis of Baseload Generation Alternatives

Prepared for

## Lindquist & Vennum, PLLP

## Big Stone Unit II

October 2, 2006

Burns & McDonnell
SINCE 1898

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# UPDATED ECONOMIC EVALUATION OF BASELOAD GENERATION ALTERNATIVES

## 1.1 INTRODUCTION

Seven utilities (Applicants) have proposed the joint development, permitting, construction, ownership, and operation of a new 630 MW coal-fired Big Stone II generation plant to be located at the existing Big Stone Plant near Milbank, South Dakota (BSPII Plant or Project). The seven joint ownership utilities include:

- Otter Tail Power Company (OTPCo)
- Central Minnesota Municipal Power Agency (CMMPA)
- Great River Energy (GRE)
- Heartland Consumers Power District (HCPD)
- Missouri River Energy Services (MRES)
- Montana-Dakota Utilities Company (MDU)
- Southern Minnesota Municipal Power Agency (SMMPA)

Each of the seven utilities, through their Resource Plan (RP) or internal resource planning efforts, had identified a need for additional baseload generation resources to serve their growing loads and/or to replace other resources in a reliable, cost-effective, and environmentally responsible manner. Joint ownership of the BSPII Plant allows the utilities to capitalize on the economies of scale of a larger baseload generation resource, capture the significant economic advantages of development of a baseload generation resource at an existing plant location, and mitigate risk in the construction and operation of a new baseload generation resource.

Burns & McDonnell (B&McD) has completed two studies to evaluate alternative baseload generation resources.

- Phase I Report on Big Stone Unit II, July 2005
- Analysis of Baseload Generation Alternatives, September 2005

The purpose of the prior studies was to evaluate the feasibility of adding an additional generation unit to the existing Big Stone station site from both quantitative and qualitative perspectives. The studies developed comparative capital costs, operating costs, performance, and emissions characteristics of different baseload generation alternatives for the existing Big Stone site, including a quantitative economic evaluation of the life-cycle capital and operating costs. The studies provided planning information that each of the Applicants could use in conducting more detailed resource planning analyses.

The Applicants retained Black & Veatch as the design engineer on the Big Stone II project. Black & Veatch recently provided the Applicants with an updated cost estimate of the Big Stone II project and other generation alternatives that identified a projected increase in costs compared to earlier planning estimates. The purpose of this "Updated Analysis of Baseload Generation Alternatives" (Study) was to determine whether the proposed Big Stone II project remains a low cost baseload alternative for the site on a life-cycle basis considering capital and operating costs

The Study focuses on three alternatives:

- 630 MW Supercritical Pulverized Coal (BSII)
- Natural Gas Fired Combined Cycle Gas Turbine (CCGT)
- Gas-Fired Combined Cycle Gas Turbine plus Wind (CCGT + Wind)

The Study evaluates the estimated busbar costs of the baseload generation alternatives over a 20 year planning period.

## 1.2 SUMMARY OF GENERATION ALTERNATIVES

Table 1 presents the updated capital cost, operation and maintenance (O&M) costs, and performance estimates for the different baseload generation technologies. For the Big Stone II project and the CCGT alternative, Black & Veatch developed the cost and performance estimates. For the CCGT plus wind case, the wind component was assumed to be purchased at a levelized cost of $60/MWh and combined with a CCGT plant.

Table 1: Technology Summary

| PROJECT TYPE | 630 MW PC Supercritical Big Stone Unit II | 500 MW Combined Cycle Greenfield | 500 MW Combined Cycle + Wind [1] |
|---|---|---|---|
| Number of Gas Turbines | N/A | 2 | 2 |
| Number of Boilers/HRSGs | 1 | 2 | 2 |
| Number of Steam Turbines | 1 | 1 | 1 |
| Steam Cycle Type | Supercritical | Subcritical | Subcritical |
| Design Fuel | 100% PRB | 100% Natural Gas | 100% Natural Gas |
| NOx Control | Low NOx Burners, SCR, OFA | Dry Low NOx Burners, SCR | Dry Low NOx Burners, SCR |
| SO2 Control | Wet Scrubber | N/A | N/A |
| Particulate Control | Baghouse | N/A | N/A |
| Ash Disposal | Landfill On Site | N/A | N/A |
| | | | |
| Net Plant Output, kW | 630,000 | 500,000 | 500,000 |
| Net Plant Heat Rate, Btu/kWh (HHV) | 9,095 | 6,704 | 7,204 |
| | | | |
| Capital Cost, $/kW (2012 COD) [2], [3] | $2,168 | $749 | $749 |
| | | | |
| Fixed O&M Cost, $/kW-Yr (2006$) [4] | $10.11 | $7.81 | $7.81 |
| Variable O&M Cost, $/MWh (2006$) | $2.23 | $3.85 | $3.85 |
| Purchase Price of Wind (2012$) | N/A | N/A | $60.00 |

| PROJECT TYPE | 630 MW PC Supercritical Big Stone Unit II | 500 MW Combined Cycle Greenfield | 500 MW Combined Cycle + Wind [1] |
|---|---|---|---|
| NOx, lb/MMBtu | 0.07 | 0.011 | 0.011 |
| SO2, lb/MMBtu | 0.10 | < 0.0051 | < 0.0051 |
| CO2, lb/MMBtu | 208 | 110 | 110 |
| Hg, lb/MWh | 2.1^10$^{-5}$ | N/A | N/A |

[1] Cost, performance, and emissions for CCGT component, assumed to operate at 48% capacity factor.
Non-firm wind energy assumed to be purchased at $60/MWh at equivalent energy to displace 40% CCGT capacity factor.

[2] Capital costs for BSII estimated as $1.366 billion for 630 MW net by Black & Veatch.

[3] Capital costs for CCGT based on B&V Study, $562/kW plus 20% Owner's Costs (2006$).
Escalated conservatively at 2.5% annually.

[4] Fixed O&M costs for BSII do not include property taxes and insurance, added subsequently in pro forma.

## 1.3 CCGT PLUS WIND

For the CCGT plus Wind case, a non-firm wind energy component was assumed to be purchased at a levelized cost of $60/MWh and combined with a new 500 MW CCGT plant based on the cost assumptions summarized above. For the CCGT project plus Wind case, the 500 MW CCGT plant is the baseload alternative being compared to the supercritical PC plant. Both are reliable, dispatchable generation resources that can be operated to meet baseload capacity and energy requirements. Wind is not a baseload resource because it does not produce dependable generation year-round at high capacity factors. Hence, the analysis does not assume construction of a wind resource, but market purchases of non-firm wind energy. The wind component was added to the CCGT project alternative to enhance its economic performance by displacing higher cost gas-fired energy production with non-firm wind energy when available. The wind component was assumed to provide energy to displace a 40 percent capacity factor on the CCGT operations.

Because the CCGT plant would be required to operate at part load dispatch levels when combined with the wind generation, the heat rate assumption for the combined cycle plant in this case was increased 500 Btu/kWh to reflect part load dispatch requirements. No other operational issues or major maintenance impacts on the CCGT plant was incorporated in the analysis.

The estimated purchase cost of $60/MWh for wind resources is based on a 2012 commercial operation date. As such, it does not include the current Renewable Energy Production Tax Credit (PTC) that was extended to December 31, 2007 for wind resources as a result of the Energy Policy Act of 2005. The current PTC for wind energy is 1.9 cents/kWh. Burns & McDonnell estimates that current new wind development costs are $40/MWh in 2006 with the PTC. Assuming a conservative escalation of 2.5% annually, the estimated cost of a 2012 wind farm would be $46.39/MWh if the PTC were extended.

## 1.4 ECONOMIC ANALYSIS ASSUMPTIONS

The following Project estimates and economic assumptions were utilized in the economic model analysis.

| | |
|---|---|
| • Capital Costs | Table 1 |
| • Heat Rate Performance Assumptions | Table 1 |
| • Emissions | Table 1 |
| • Fuel Cost Forecast | Section 1.5 |
| • Purchased Wind Cost | $60/MWh Levelized |
| • O&M Cost Assumptions: | |
| Fixed O&M Costs | Table 1 |
| Insurance | 0.05% of Capital Cost |
| Property Taxes | 0.5% of Capital Cost |
| Variable O&M Costs | Table 1 |
| Emissions Allowance Costs | $700/ton $SO_2$<br>$1,300/ton $NO_x$ (ozone season)<br>$35,000/lb Mercury |

- Operating Assumptions:

| | |
|---|---|
| Overall Capacity Factor | 88.0% for baseload comparison |

## 1.5 FUEL COST FORECAST

Table 2 presents the base case fuel cost assumptions used in the economic model analysis for each of the alternatives.

Table 2: Fuel Cost Assumptions

| Technology | Fuel | Delivered Cost Estimate | Escalation |
|---|---|---|---|
| BSII Unit | PRB Coal | $1.71/MMBtu (2010$) | 2.9% |
| CCGT Unit | Natural Gas | $7.60/MMBtu (2011$) | 3.0% |

The PRB fuel cost forecast was provided by Otter Tail Power Company. This forecast assumes an overall delivered cost for PRB coal of $1.71/MMBtu in 2010. In September 2006, the NYMEX futures price for Henry Hub natural gas commodity supply in 2011 is $7.20/MMBtu. A conservative transportation cost of $0.40/MMBtu was added to this supply cost for a delivered cost of $7.60/MMBtu in 2011.

## 1.6 FINANCING AND ECONOMIC ASSUMPTIONS

The following financing and economic assumptions were utilized in the economic model analysis. The economic model analyses were prepared under two distinct ownership and cost of capital structures: investor owned utility and public power utility. Of the seven participating utilities, OTPCo and MDU are investor owned utilities. CMMPA, GRE, MRES, HCPD and SMMPA are public power utilities.
Note that each of the seven participating utilities will have its own financing plan, capital structure, rate of return, tax rate, and depreciation schedule for its share of the BSPII Project, and the specific cost of capital assumptions will vary. The following assumptions are used to represent the relative difference in capital cost financing for the different ownership structures.

- Financing Assumptions (Investor Owned Utility):

| | |
|---|---|
| Interest Rate | 7.5% |
| Term | 20 years |
| Debt/Equity Percentage | 50%/50% |
| Return on Equity | 12.0% |
| Construction Financing Fees | 0.50% |
| Permanent Financing Fees | 1.00% |

| | |
|---|---|
| Construction Financing | 48 months for PC<br>24 months for CCGT |

- Financing Assumptions (Public Power):

| | |
|---|---|
| Interest Rate | 6.0% |
| Term | 30 years |
| Debt/Equity Percentage | 100%/0% |
| Construction Financing Fees | 0.50% |
| Permanent Financing Fees | 1.00% |
| Construction Financing | 48 months for PC<br>24 months for CCGT |

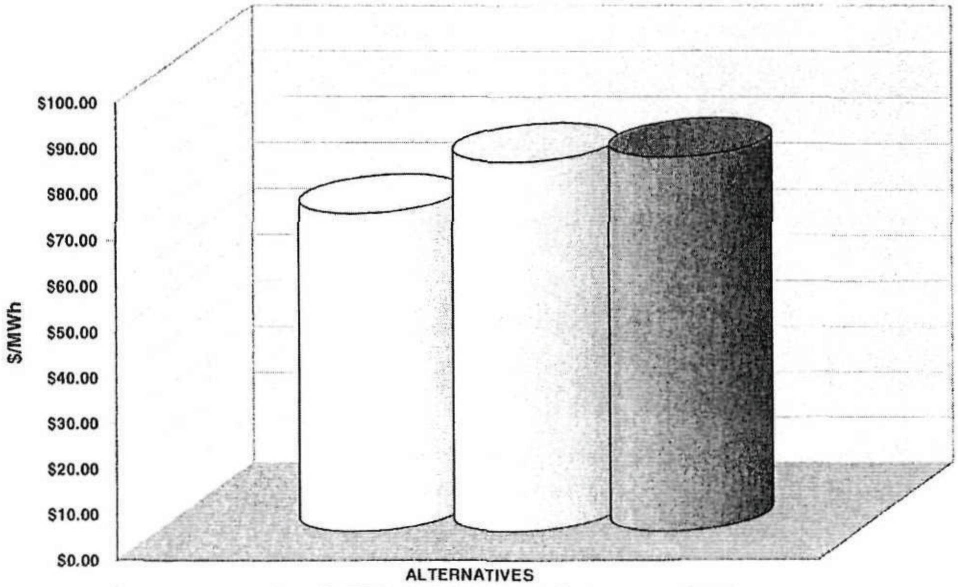
- Economic Assumptions:

| | |
|---|---|
| O&M Inflation | 2.5% per annum |
| Construction Cost Inflation | 2.5% per annum |
| Discount Rate (Investor Owned Utility) | 9.75% |
| Discount Rate (Public Power) | 6.0% |
| Effective Tax Rate (IOU only) | 40.0% |
| Book Depreciation | 30 years |
| Tax Depreciation (IOU only) | 20 years |

## 1.7 SUMMARY OF ECONOMIC ANALYSIS

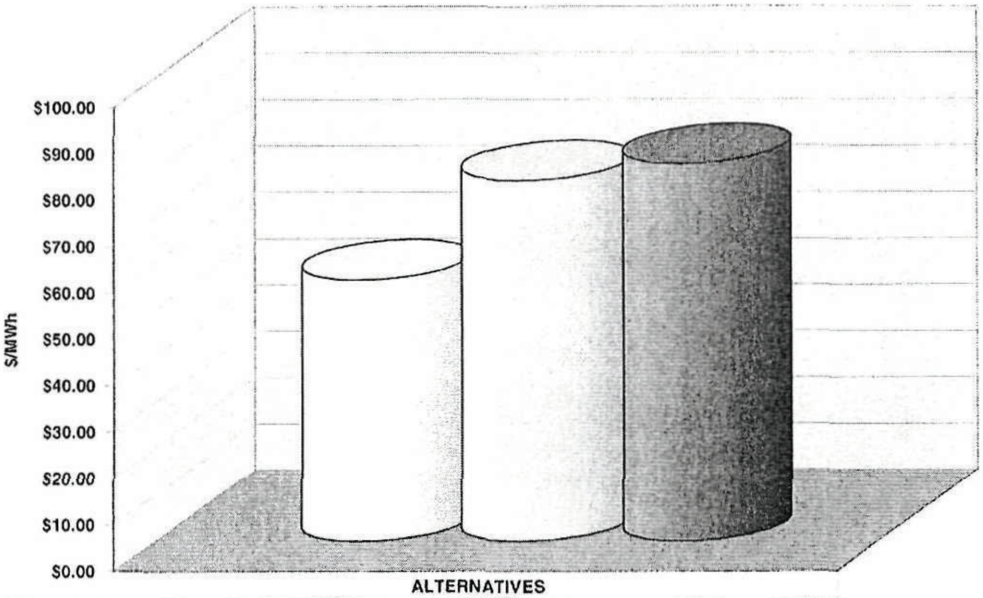
B&McD prepared an economic model analysis for each of the baseload generation alternatives based on the cost and performance estimates presented in Table 1. A 20-year economic analysis was prepared and the levelized busbar cost of each alternative was determined under two ownership structures: investor-owned utility (IOU) and public power utility (PPU). Figures 1 and 2 present graphs showing the 20-year levelized busbar power costs in 2012$ for each of the baseload generation alternatives under both investor owned utility and public power utility ownership.

Figure 1: Levelized Busbar Costs (2012$) – Investor Owned Utility



| | |
|---|---|
| ☐ 630 BSII IOU | $69.62 |
| ☐ 500 CCGT +Wind IOU | $80.78 |
| ☐ 500 CCGT IOU | $81.89 |

Figure 2: Levelized Busbar Costs (2012$) – Public Power



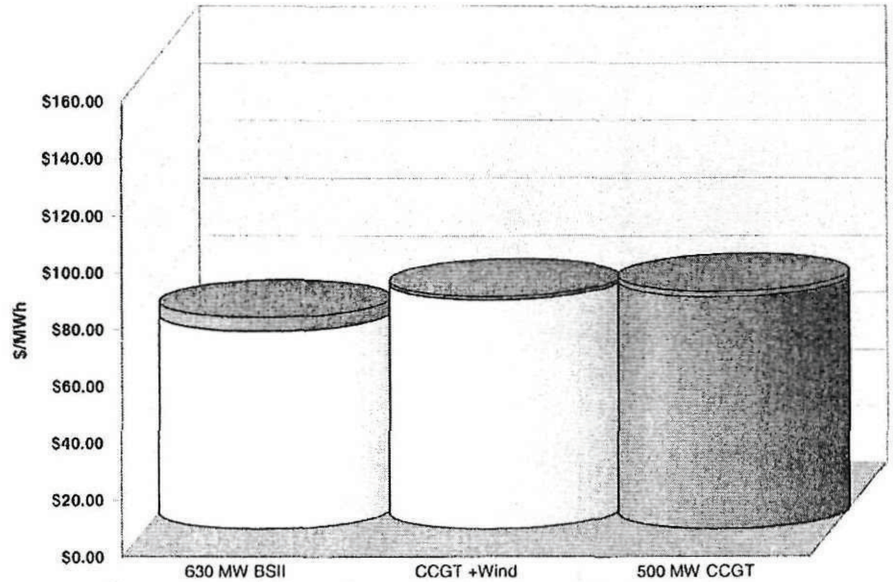
| | |
|---|---|
| ☐ 630 BSII PPU | $56.38 |
| ☐ 500 CCGT +Wind PPU | $77.77 |
| ▨ 500 CCGT PPU | $81.30 |

As indicated in Figures 1 and 2, the 630 MW supercritical BSII project alternative continues to represent the lowest cost baseload alternative for the participating utilities and their customers. Although the combined cycle plant has lower capital costs, high natural gas fuel cost makes it uneconomical for baseload dispatch. The CCGT plus wind combination reflects the next lowest cost resource choice, but is 16 percent higher cost for the IOU utilities and 38 percent higher cost for the public power utilities compared to the BSII alternative for baseload energy production.

## 1.8 SUMMARY OF CARBON COST SCENARIOS

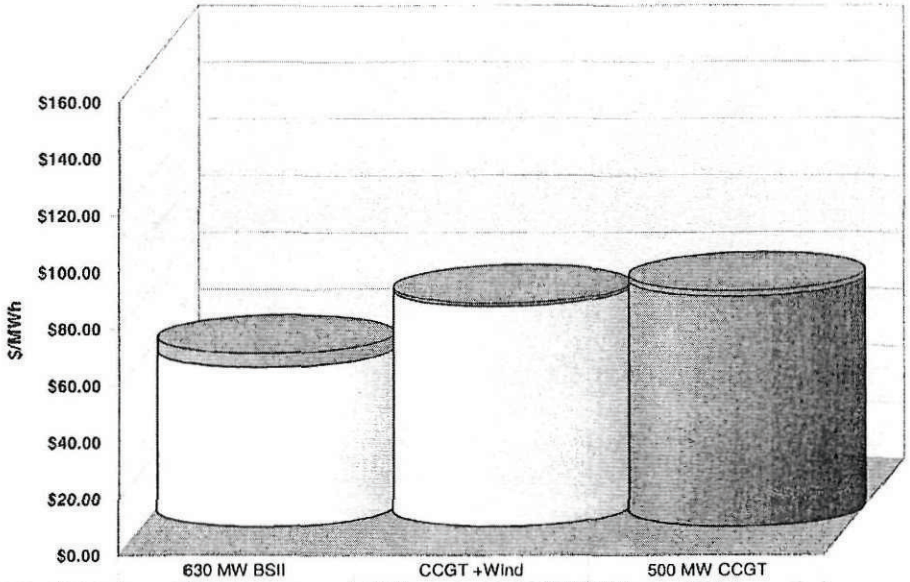
The Minnesota Public Utilities Commission has identified a range of values for a carbon dioxide environmental cost value of $0.35/ton to $3.64/ton. The inclusion of a carbon dioxide environmental cost value (through imposition of a carbon tax or otherwise) would cause an increase in the busbar cost of power for a new baseload resource. Figures 3 and 4 below present the impact of the $3.64/ton $CO_2$ environmental cost value on the economic modeling results under both investor owned utility and public power utility ownership structures. The subcritical PC Unit will emit approximately 4.6 million tons of $CO_2$ per year. At a $3.64/ton $CO_2$ environmental cost value, the levelized busbar cost will be increased by $4.98/MWh under investor owned utility ownership and the levelized busbar cost will be increased by $4.94/MWh under public power utility ownership.

Figure 3: Levelized Busbar Costs – Investor Owned Utility – $CO_2$ Environmental Cost Value



| | 630 MW BSII | CCGT +Wind | 500 MW CCGT |
|---|---|---|---|
| Total Busbar Cost | $74.49 | $81.89 | $83.79 |
| ☐ Carbon Tax | $4.87 | $1.12 | $1.90 |
| ■ Busbar Cost w/o Carbon Tax | $69.62 | $80.78 | $81.89 |

Figure 4: Levelized Busbar Costs – Public Power – $CO_2$ Environmental Cost Value



| | 630 MW BSII | CCGT +Wind | 500 MW CCGT |
|---|---|---|---|
| Total Busbar Cost | $61.20 | $78.92 | $83.26 |
| ☐ Carbon Tax | $4.82 | $1.15 | $1.96 |
| ■ Busbar Cost w/o Carbon Tax | $56.38 | $77.77 | $81.30 |

As indicated in Figures 3 and 4, the inclusion of a carbon environmental cost value of $3.64/ton increases the levelized busbar costs of all the alternatives, but does not change the relative economics of the baseload alternatives.

The break-even carbon dioxide environmental cost value to equalize the 630 MW supercritical BSII unit levelized busbar cost with the CCGT plus Wind levelized busbar cost is approximately $11.10/ton for the investor owned utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $84.10/MWh, which is an increase of 21 percent compared to the base case BSII cost of $69.62/MWh for an IOU participant.

The break-even carbon dioxide environmental cost value to equalize the 630 MW supercritical BSII unit levelized busbar cost with the CCGT plus Wind levelized busbar cost is approximately $21.70/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $84.40/MWh, which is an increase of 49 percent compared to the base case BSII cost of $56.38/MWh for a public power participant.

Overall, inclusion of a carbon environmental cost value in the evaluation would not impact the baseload generation economic results unless a significant cost was imposed.

## 1.9 CONCLUSIONS

The Updated Analysis of Baseload Generation Alternatives supports the following conclusions:

- The Big Stone II unit alternative remains a low cost baseload resource alternative for the participating utilities and their customers.
- Although the CCGT alternative has lower capital costs, the high natural gas fuel cost, makes it uneconomical for baseload dispatch.
- The CCGT plus Wind case reflects the next lowest cost baseload energy resource, but is 16 percent higher cost for the IOU utilities and 38 percent higher cost for the public power utilities compared to the Big Stone II alternative.
- Inclusion of a carbon environmental cost value in the evaluation would not impact the results unless a significant cost was imposed.

## 1.10 PTC SENSITIVITY

The estimated purchase cost of $60/MWh for wind resources is based on a 2012 commercial operation date. As such, it does not include the current Renewable Energy PTC that was extended to December 31, 2007 for wind resources in the Energy Policy Act of 2005. The current PTC for wind energy is 1.9 cents/kWh. A sensitivity analysis was prepared assuming that the PTC is further extended or replaced with a similar tax credit. In the sensitivity analysis, the estimated levelized purchase cost of wind energy was reduced to $46.39/MWh for the CCGT plus wind case.

For the investor-owned utilities, assuming a PTC is re-established lowers the levelized busbar cost of the CCGT plus wind case to $74.59/MWh. This cost is 7 percent higher than the BSII supercritical PC unit cost of $69.62/MWh. For the public power utilities, assuming a PTC is re-established lowers the levelized busbar cost of the CCGT plus wind case to $71.58/MWh. This cost is 27 percent higher than the BSII supercritical PC unit cost of $56.38/MWh. The inclusion of a PTC for wind energy does not change the relative economics of the baseload generation resource choice.

### 1.10.1 Investor-Owned Utility PTC and Carbon Cost Sensitivity Results

For the investor-owned utilities, assuming a PTC is re-established results in a levelized busbar cost of $75.71/MWh for the CCGT case plus wind case including a carbon environmental cost value of $3.64/ton. This cost is higher than the BSII supercritical PC unit cost of $74.49/MWh for an IOU. The inclusion of a PTC for wind energy and the inclusion of a carbon environmental cost value of $3.64/ton does not change the relative economics of the alternatives. The break-even carbon dioxide environmental cost value to equalize the BSII supercritical PC unit levelized busbar cost with the CCGT plus wind levelized busbar cost is approximately $5.00/ton in 2006$ for the investor owned utility ownership structure.

### 1.10.2 Public Power Utility PTC and Carbon Cost Sensitivity Results

For the public power utilities, assuming a PTC is re-established results in a levelized busbar cost of $72.73/MWh for the CCGT case plus wind case including a carbon environmental cost value of $3.64/ton. This cost is higher than the BSII supercritical PC unit cost of $61.20/MWh for a public power utility. The inclusion of a PTC for wind energy and the inclusion of a carbon environmental cost value of $3.64/ton does not change the relative economics of the alternatives. The break-even carbon dioxide environmental cost value to equalize the BSII supercritical PC unit levelized busbar cost with the CCGT plus wind levelized busbar cost is approximately $15.40/ton in 2006$ for the public power utility ownership structure.

## 1.11 STATEMENT OF LIMITATIONS

In preparation of this Study, Burns & McDonnell has made certain assumptions regarding future market conditions for construction and operation of a new power generating facilities. While we believe the use of these assumptions is reasonable for the purposes of this Study, B&McD makes no representations or warranties regarding future inflation, labor costs and availability, material supplies, equipment availability, weather, and site conditions. To the extent future actual conditions vary from the assumptions used herein, perhaps significantly, the estimated costs presented in the Study will vary.

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