SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

CASE NO. EL05-022

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER COMPANY

ON BEHALF OF THE BIG STONE II CO-OWNERS

FOR AN ENERGY CONVERSION FACILITY SITING PERMIT FOR THE

CONSTRUCTION OF THE BIG STONE II PROJECT

DIRECT TESTIMONY

OF

JEFFREY J. GREIG

GENERAL MANAGER OF THE BUSINESS & TECHNOLOGY SERVICES DIVISION

BURNS & McDONNELL ENGINEERING COMPANY

MARCH 15, 2006

TESTIMONY OF JEFFREY J. GREIG

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BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF JEFFREY J. GREIG

I. INTRODUCTION

Q: Please state your name and business address.

A: Jeffrey (Jeff) J. Greig, Burns & McDonnell Engineering Co., 9400 Ward Parkway, Kansas City, MO, 64114.

Q: By whom are you employed, and in what capacity?

A: I am employed by Burns & McDonnell Engineering Company. I am the General Manager of the Business & Technology Services Division of the company.

Q: What are your responsibilities in your current position?

A: The Business & Technology Services Division is a consulting group specializing in generation resource planning, transmission planning, financial and rate analyses, project development services, information management and technology consulting, security consulting, and energy services. We consult with utilities, government agencies, and private companies.

Q: What is your educational background?

A: I have Bachelors Degrees in Finance and Economics from Eastern Illinois University, and a Masters Degree in Economics from Iowa State University.

Q: What is your employment history?

A: I have 19 years of experience as a consultant in the electric power industry. My background includes generation resource planning, feasibility studies, siting studies, market assessments, project development, and asset due diligence.

Q: Have you previously provided testimony before the South Dakota Public Utilities Commission or other regulatory agencies?

A: I have not appeared before the South Dakota PUC. I have provided written and oral testimony before the Wisconsin Public Service Commission regarding a site certificate for a gas-fired project. I have provided written and oral testimony before the Ohio Power Siting Board regarding a site certificate for a gas-fired project. I have prepared written testimony regarding a site certificate and rate principles filing presented to the Iowa Utilities Board. I have prepared written testimony regarding power supply planning for the New Mexico Public Regulation Commission. I have prepared written testimony regarding a generation asset transfer for the Illinois Commerce Commission, and I have provided written and oral testimony regarding a generation asset transfer for the Federal Energy Regulatory Commission (FERC).

II. PHASE I REPORT

Q: What is the Phase I Report?

A: The Phase I Report is a report finalized by Burns & McDonnell in July 2005 entitled "Phase I Report Big Stone Unit II." A copy is attached to the testimony of Stephen Gosoroski as Applicants' Exhibit 24-A. The existing Big Stone station in South Dakota is a nominal 450-megawatt (MW) coal-fired generating plant owned by Otter Tail Power Company, Northwestern Energy (formerly Northwestern Public Service Company), and Montana-Dakota Utilities. These owners and other utility companies undertook a screening analysis of potential generation alternatives that is outlined in the testimony of Mr. Mark Rolfes of Otter Tail Power Company. Following and as part of the overall screening analysis, Burns & McDonnell was engaged to prepare the Phase I Report on Big Stone Unit II.

Q: What is the objective of the Phase I Report?

A: The objective of the Phase I Report was to evaluate the feasibility of adding an additional generation unit (Unit II) to the existing Big Stone station site from both quantitative and qualitative perspectives. The Phase I Report developed comparative capital costs, operating costs, performance, and emissions characteristics of different generation alternatives for the existing Big Stone site. The Phase I Report also included a quantitative economic evaluation of the life-cycle capital and operating costs of the different generation alternatives.

Q: What were your responsibilities for the Phase I Report on Big Stone Unit II completed by Burns & McDonnell in July 2005?

A: I managed the economic pro forma analysis of the generation alternatives. As such, I was responsible for the overall quality of the economic evaluation completed by a staff engineer in my group.

Q: What generation alternatives were considered in the economic evaluation of the Phase I Report on Big Stone Unit II?

A: Seven generation alternatives were evaluated in the economic analysis: (1) 600 MW supercritical PC unit; (2) 450 MW supercritical PC unit; (3) 300 MW subcritical PC unit; (4) 600 MW subcritical circulating fluidized bed (CFB) unit; (5) 450 MW subcritical CFB unit; (6) 300 MW subcritical CFB unit; and (7) 500 MW Combined Cycle Gas Turbine (CCGT) unit.

Q: What was the conclusion of the Phase I Report on Big Stone Unit II?

A: The Phase I Report concluded that a 600 MW supercritical pulverized coal (PC) plant represented the lowest cost generation alternative of the technologies evaluated for the Big Stone station site on a life-cycle basis considering capital and operating costs.

Q: Describe the process Burns & McDonnell used to develop the economic evaluation in the Phase I Report.

A: First, the capital cost, performance, and O&M cost estimates for the different generation alternatives are developed. In the Direct Testimony of Mr. Stephen Gosoroski of Burns & McDonnell, he testifies to the effort conducted by the Development Engineering group to develop these estimates. These estimates are used as the key inputs into a pro forma economic model that determines the annual busbar cost of power for each alternative on a revenue requirements basis over a 20-year planning period. Busbar refers to the cost of power without transmission, distribution, and ancillary service charges. Effectively the busbar cost is the cost of the power at the plant substation. The technical inputs were combined with economic, financing, and fuel cost assumptions to develop the overall busbar power costs. Two different economic models were prepared to reflect the different potential ownership structures.

Q: Why do you use a 20-year planning period ?

A: In my experience, a 20-year planning period is adequate to capture the life cycle cost performance of generation resource alternatives. The plants themselves will have a useful life that exceeds 20 years, but the relative economics between the alternatives will be demonstrated over the first 20 years of an economic evaluation. In the later years, the annual fuel and operating costs will continue to escalate, but generally in similar fashion. The latter year costs are significantly discounted and do not change the results of the analysis.

Q: Explain the need to prepare two pro forma models for different ownership structures.

A: Two different economic models were prepared to reflect the different potential ownership structures of public power (i.e., municipal utilities such as Missouri River Energy Services and cooperatives such as Great River Energy) and investor-owned utilities (such as Otter Tail). These types of utilities generally use different financing structures and have different revenue requirements. The public power model was intended to capture economic results that would be expected for a cooperative, municipal utility, or joint action agency. The public power model assumed tax-exempt debt financing through bonds for 100% of the estimated total project costs. Also, no income tax liability was estimated. For the investor-owned model, a 50% debt/50% equity financing structure was assumed, and an income tax liability component was estimated. The revenue requirements of each ownership structure were also determined differently.

Q: Explain the term revenue requirements and the different assumptions for the two ownership structures.

A: Revenue requirements are the total costs that need to be recovered on an annual basis, both operating costs and capital costs. For the public power utility model, the annual revenue requirements are defined as fuel costs, fixed and variable O&M costs, and debt service costs of principal repayment and interest. The debt service costs are estimated based on the total cost of the generation alternative and the financing assumptions. For the investor-owned utility model, the capital cost component of revenue requirements are defined differently. The revenue requirements are defined as fuel costs, fixed and variable O&M costs, interest on debt, depreciation expense, return on invested equity, and a tax liability component.

Q: What were the specific financing assumptions used in the economic analysis?

A: The public power model assumed tax-exempt debt financing through bonds for 100% of the estimated total project costs. The bond term was assumed as 30 years with a 6.0% interest rate. For the investor-owned model, a 50% debt/50% equity financing structure was assumed. The bond term was assumed as 20 years with a 7.5% interest rate for the debt component. The return on equity was assumed to be 12.0%. These financing assumptions were used for each of the generation alternatives.

Q: What were the other key assumptions used in the economic analysis?

A: The generation alternatives were evaluated as potential baseload resources. Therefore, the economic model was based on a high availability and high capacity factor operations of 88%. Additional assumptions included general escalation rates for capital and operating costs of 2.5% annually, and an effective tax rate of 40% for the investor-owned utility model. The other important estimates were the fuel cost forecasts.

Q: What was the basis for the fuel cost forecasts used in the economic analysis?

A: All of the solid fuel generation alternatives used the same fuel – Powder River Basin (PRB) coal. The PRB fuel cost forecast was based on a review of delivered costs to the existing Big Stone station escalated by 2.0% annually. This resulted in an overall delivered cost estimate for PRB coal of $1.28/MMBtu in 2010. A natural gas combined cycle case was prepared as a benchmark comparison. The natural gas cost forecast was based on the February 2004 NYMEX futures price for Henry Hub natural gas commodity supply in 2009 of $4.61/MMBtu plus a transportation cost. The Department of Energy's *Annual Energy Outlook 2004* was used as the basis of real escalation adjustments for 2010 to 2025 with a nominal escalation rate of 2.0%. This resulted in an overall delivered cost estimate for natural gas of $5.10/MMBtu in 2010.

Q: Did the economic analysis include costs for emissions allowances?

A: Yes. The economic models assumed a cap-and-trade system or similar emissions reduction structure would be in place and emission allowances would be required for SO_2, NO_x and mercury emissions. The emission allowance costs for SO_2 were estimated as $700/ton through 2014, $1,109/ton thereafter. The emission allowance costs for NO_x were estimated as $1,300/ton through 2014, $1,507/ton thereafter. The emission allowance costs for mercury were estimated as $35,000/lb. These allowance costs were escalated similar to the O&M costs.

Q: What were the specific results of the economic analysis?

A: For the public power utility ownership model, the lowest cost generation alternative was the 600 MW supercritical PC unit with an estimated busbar cost of $38.26/MWh in 2010. This was followed by the 600 MW CFB unit ($40.21/MWh), the 450 MW PC unit ($41.28/MWh), and the 450 MW CFB unit ($43.95/MWh). The highest cost generation alternative was the 500 MW CCGT unit ($55.55/MWh). For the investor-owned utility ownership model, the lowest cost generation alternative was also the 600 MW supercritical PC unit with an estimated busbar cost of $47.05/MWh in 2010. This was followed by the 600 MW CFB unit ($49.37/MWh), the 450 MW PC unit ($51.18/MWh), and the 450 MW CFB unit ($54.53/MWh). The highest cost generation alternative was the 500 MW CCGT unit ($56.95/MWh).

The economic evaluation demonstrates that there is an economy of scale benefit within the coal-fired resource alternatives. The estimated busbar costs consistently declined for larger unit sizes, with 600 MW representing the lowest cost alternative evaluated. The economic evaluation demonstrates that the difference in costs between the pulverized coal and CFB technologies are not significant, but there is a cost advantage for the PC technology due to its lower capital cost and higher efficiency for PRB fuel. The economic evaluation also demonstrates that a coal-fired generation resource has a significant economic advantage compared to a high-efficiency natural gas CCGT unit for baseload capacity and energy requirements due to the fuel cost differentials between coal and natural gas.

Q: What other analyses were prepared in the Phase I Report?

A: We prepared different sensitivity analyses to evaluate the changes in results for changes in key inputs. We prepared sensitivity analyses for the following:

- Capital Cost plus or minus 10%
- Interest Rate plus or minus 1.0%
- Capacity Factor plus or minus 5%
- Fuel Cost plus or minus 20%
- O&M Costs plus or minus 10%

Q: What were the results of the sensitivity analyses?

A: For the investor-owned utility, the overall busbar cost for the coal-fired generation alternatives is most sensitive to capital cost and fuel cost. A ten percent increase in the capital cost of a 450 MW PC unit would increase the levelized busbar cost by $3.63/MWh. For the public power utility, the overall busbar cost for the coal-fired generation alternatives is most sensitive to interest rate and fuel cost. A one percent increase in the interest rate for financing a 450 MW PC unit would increase the levelized busbar cost by $3.44/MWh. For the gas-fired combined cycle unit, the overall busbar cost is most sensitive to fuel cost.

A separate capacity factor analysis was prepared to identify the cross-over point between the economics of a 450 MW PC unit and a 500 MW CCGT unit. For both the investor-owned utility ownership and public power utility ownership, a 450 MW PC unit represented a lower cost resource at the base case capacity factor assumption of 88%. The cross-over point at which the busbar costs would be equal between the two alternatives occurred at a 49% capacity factor for the public power utility model and a 71% capacity factor for an investor-owned utility model. At intermediate capacity factors below these values, the gas-fired CCGT resource would demonstrate an economic advantage.

Q: Explain the term levelized.

A: Generally, costs increase over time due to inflation impacts on operating costs and fuel costs. Over a long-term year planning period, a levelized busbar cost represents a single, all-in power cost that captures measures of both cost escalation and the time value of money. For the selected discount rate, the owner would be indifferent to the levelized busbar cost throughout the planning period or a power cost that started lower but escalated annually. A levelized busbar cost is a useful summary measure for comparing alternatives.

III. ANALYSIS OF BASELOAD GENERATION ALTERNATIVES

Q: Did Burns & McDonnell prepare any additional studies to evaluate the economics of different generation alternatives?

A: Yes. Subsequent to the Phase I Report on Big Stone Unit II, Burns & McDonnell prepared a study titled, "Analysis of Baseload Generation Alternatives – Big Stone Unit II" dated September 2005. This study and report is included as Applicants' Exhibit 23-A.

Q: What was the purpose of the Generation Alternatives Study?

A: The construction and operation of Big Stone Unit II will necessitate the construction of new transmission lines in Minnesota (and South Dakota) to reliably deliver the output to the loads of some 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. The Generation Alternatives Study was prepared in connection with the Minnesota CON. The objectives were similar to the Phase I Report but considered an expanded set of generation alternatives. The Generation Alternatives Study evaluated comparative capital costs, operating costs, performance, emissions characteristics, and economics of different baseload generation technologies. However, unlike the Phase I Report, the new analysis was not limited to generation alternatives located at the Big Stone site but was instead designed to provide a broader overview of generation alternatives for meeting the Applicants' needs for 600 MW of baseload power.

Q: What were your responsibilities for the Generation Alternatives Study?

A: I was the overall project manager for the study, and I managed the economic pro forma analysis of the generation alternatives.

Q: What alternatives were considered in the Generation Alternatives Study?

A: Six alternative baseload power plant technologies were evaluated. From the Phase I Report on Big Stone Unit II, the low cost alternative of a 600 MW supercritical PC unit was carried forward. The five other generation technologies included: (1) 600 MW subcritical PC unit, (2) 600 MW CCGT unit, (3) 535 MW IGCC unit, (4) 50 MW 100% Biomass unit, and (5) 600 MW CCGT unit plus Wind.

Q: What was the conclusion of the Generation Alternatives Study?

A: This second study reconfirmed that a 600 MW PC plant represents the lowest cost generation alternative of the baseload technologies evaluated on a life-cycle basis considering capital and operating costs. The overall economic difference between subcritical and supercritical PC technology was not material. The supercritical technology has been selected for Big Stone Unit II to minimize emissions.

Q: Did you include any sensitivities with respect to a possible carbon tax in the Generation Alternatives Study?

A: Yes. The Generation Alternatives Study also included a carbon tax sensitivity. The study assumed a carbon tax of $3.64/ton of CO_2 added to all of the generation alternatives. This figure is the high end externality value used by the Minnesota Public Utilities Commission to monetize CO_2 emissions from generating stations located in Minnesota. The Minnesota Commission does not apply a CO_2 externality value for generation located outside of Minnesota, and South Dakota does not apply externality values in resource decisions. Nevertheless, even applying the $3.64/ton value, the economic conclusion that a 600 MW PC plant represents the lowest cost generation alternative of the baseload technologies evaluated was confirmed.

Q: Was the process Burns & McDonnell used to develop the economic evaluation in the Generation Alternatives Study the same as it was in the Phase I Report?

A: Yes. First, the capital cost, performance, and O&M cost estimates for the different generation alternatives were developed by Burns & McDonnell's Development Engineering Group. These estimates were used as the key inputs into a pro forma economic model that determined the annual busbar cost of power for each alternative on a revenue requirements basis over a 20-year planning period.

Q: Were the financing assumptions for the two different ownership structures the same in the Generation Alternatives Study as they were in the Phase I Report?

A: Yes.

Q: Were the other key operating and economic assumptions the same in the Generation Alternatives Study as they were in the Phase I Report?

A: Yes.

Q: What was the basis for the fuel cost forecasts used in the Generation Alternatives Study?

A: The PRB fuel cost forecast for the 600 MW supercritical PC unit and 600 MW subcritical PC unit was based on a review of delivered costs to the existing Big Stone station escalated by 2.0% annually. This resulted in an overall delivered cost estimate for PRB coal of $1.21/MMBtu in 2007. For the IGCC alternative, it was assumed that an Illinois Basin bituminous coal would be the feedstock. Based on current market pricing for this commodity, an overall delivered cost estimate of $2.47/MMBtu in 2007 was used. In September 2005, the NYMEX futures price for Henry Hub natural gas commodity supply in 2010 was $7.45/MMBtu. A transportation cost would have to be added to this supply cost. However, the U.S. was experiencing record natural gas prices over $12.00/MMBtu in the aftermath of the hurricanes that struck the Gulf Coast region. Therefore, a more conservative assumption was used in the study based on a delivered cost of $7.00/MMBtu for 2011 and a 2.5% escalation rate. For the biomass alternative, Burns & McDonnell estimated a delivered cost of $5.98/MMBtu for a dedicated wood crop such as hybrid poplar.

Q: What was the basis for the cost of wind resources used in the Generation Alternatives Study?

A: For the Wind plus CCGT alternative, it was assumed that the wind component would be purchased from independent power developers at a levelized cost of \$50/MWh for a 2011 in-service date. The current Renewable Energy Production Tax Credit (PTC) of 1.9 cents/kWh expires in 2007 and may not be available as a subsidy to lower the cost of wind energy.

Q: Did you include costs for emissions allowances in the Generation Alternatives Study?

A: Yes. The economic models assumed emission allowances would be required for SO_2, NO_x and mercury emissions. The emission allowance costs for SO_2 were estimated as \$700/ton. The emission allowance costs for NO_x were estimated as \$1,300/ton during the ozone season. The emission allowance costs for mercury were estimated as \$35,000/lb. These allowance costs were escalated annually.

In addition, as mentioned, the Generation Alternatives Study included a separate carbon tax scenario. For each of the baseload generation alternatives, an assumed carbon tax of \$3.64/ton of CO_2 was included in a sensitivity analysis.

Q: Are CO_2 emissions currently subject to a carbon tax in the US?

A: No. There is no CO_2 or carbon tax in the US.

Q: What are the respective CO_2 emissions of the generation alternatives?

A: Coal is the most carbon intensive fuel at 208 lbs/MMBtu, but all fossil fuels release CO_2 when combusted. Natural gas for the CCGT case releases approximately 110 lbs/MMBtu. Wind has no carbon dioxide emissions, so a blended Wind plus CCGT case will have less emissions. The combustion of biomass feedstock releases CO_2, but it is assumed to be equal to the uptake of CO_2 in a closed-loop biomass system for a net emissions rate of zero. For the IGCC facility based on bituminous coal, a CO_2 emissions rate of 200 lbs/MMBtu was used.

Q: Is IGCC promoted as a technology to minimize CO_2 emissions?

A: Yes, but only if CO_2 is captured and sequestered. Neither of the two operating IGCC plants in the U.S. capture CO_2 and most of the proposed IGCC facilities in development do not plan to initially capture or sequester CO_2. Without the capture of CO_2, the carbon emissions from an IGCC facility are similar to a supercritical PC unit. Because IGCC technology creates a syngas, there is a technological capability of scrubbing CO_2 from the syngas, and this capability is enhanced if an oxygen-blown gasifier is used and a more concentrated steam is created. However, CO_2 capture adds significant costs and technical challenges to an IGCC plant, since the technology has not been commercially demonstrated.

Q: What were the specific results of the economic evaluation developed in the Generation Alternatives Study?

A: For the public power utility ownership model, the lowest cost generation alternative was the 600 MW subcritical PC unit with an estimated levelized busbar cost of $47.21/MWh over the 2011 to 2030 planning period. This was closely followed by the 600 MW supercritical unit at $47.37/MWh. The 600 MW Wind plus CCGT alternative was next at $70.57/MWh, which is 49% higher than the 600 MW supercritical PC unit. The 535 MW IGCC unit ($71.05/MWh), the 600 MW CCGT unit ($75.61/MWh), and the 50 MW biomass unit ($156.02/MWh) all resulted in higher costs. For the investor-owned utility ownership model, the lowest cost generation alternative was also the 600 MW subcritical PC unit with an estimated levelized busbar cost of $58.41/MWh over the 2011 to 2030 planning period. This was closely followed by the 600 MW supercritical unit at $58.81/MWh. The 600 MW Wind plus CCGT alternative was next at $72.89/MWh, which is 24% higher than the 600 MW supercritical PC unit. The 600 MW CCGT unit ($77.94/MWh), the 535 MW IGCC unit ($83.84/MWh), and the 50 MW biomass unit ($170.52/MWh) all resulted in higher costs.

The economic evaluation demonstrates that a coal-fired generation resource has a significant economic advantage compared to a natural gas CCGT unit or a wind plus CCGT alternative due to the fuel cost differentials between coal and natural gas. The overall economic difference between subcritical and supercritical PC technology at 600 MW was not material. IGCC technology was not competitive on an economic comparison with the PC technology. The supercritical technology has been selected for Big Stone Unit II to minimize emissions.

Q: What were the specific results of the carbon economic evaluation developed in the Generation Alternatives Study?

A: The conclusions did not change when an assumed carbon tax of $3.64/ton of CO_2 was added. For the public power utility ownership model, the levelized busbar cost of the 600 MW supercritical PC unit increased to $52.22/MWh. The 600 MW Wind plus CCGT alternative was $71.77/MWh, a difference of 37%. For the investor-owned utility ownership model, the levelized busbar cost of the 600 MW supercritical PC unit increased to $63.69/MWh. The 600 MW Wind plus CCGT alternative was $74.08/MWh, a difference of 16%.

For the public power utility ownership model, a carbon tax of $23.00/ton would be required to equalize the levelized busbar cost of the 600 MW supercritical PC unit with the Wind plus CCGT alternative at a cost of approximately $78/MWh. This represents an increase of 65 percent compared to the base case cost of $47.37/MWh for the 600 MW supercritical PC unit alternative. For the investor-owned utility ownership model, a carbon tax of $14.00/ton would be required to equalize the levelized busbar cost of the 600 MW supercritical PC unit with the

Wind plus CCGT alternative at a cost of approximately $77/MWh. This represents an increase of 31 percent compared to the base case cost of $58.81/MWh for the 600 MW supercritical PC unit alternative.

Q: What conclusion did you reach on the basis of the economic analysis performed?

A: The economic analyses prepared for the Phase I Report and the subsequent Generation Alternatives Study demonstrate that the 600 MW supercritical PC plant is a least-cost generation alternative for the Big Stone station site on a life-cycle basis considering capital and operating costs compared to numerous other generation alternatives.

Q: Does this conclude your testimony?

A: Yes.

Analysis of Baseload Generation Alternatives

Big Stone Unit II

September 2005
39561

Burns & McDonnell
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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

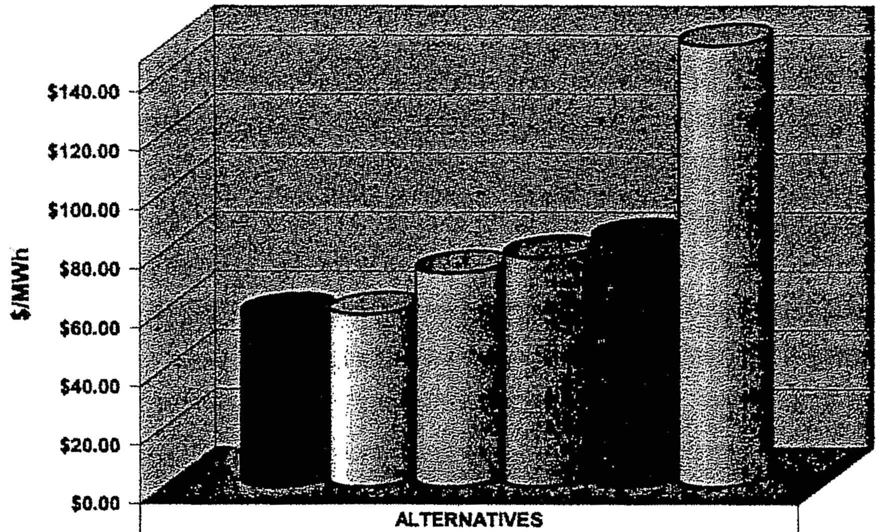
PROJECT TYPE	600 MW PC Supercritical New Big Stone Unit II	600 MW PC Subcritical New Unit at Big Stone Site	50 MW Biomass New Unit at Big Stone Site	600 MW Combined Cycle Greenfield	535 MW IGCC Greenfield
Technology Rating	Mature	Mature	Mature	Mature	Development
Number of Gas Turbines	N/A	N/A	N/A	2	2
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

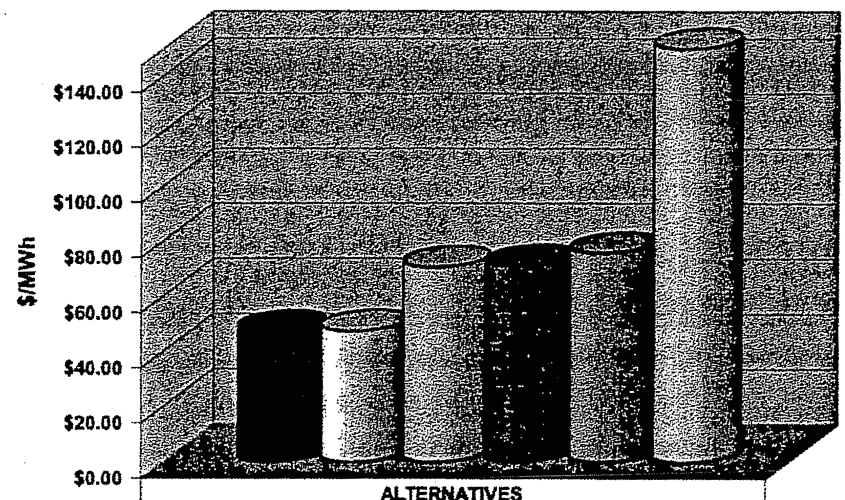
B&McD prepared an economic model analysis for each of the six baseload generation alternatives based on the cost and performance estimates presented in Table 1-1. A 20-year economic analysis was prepared and the levelized busbar cost of each alternative was determined under two ownership structures: 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.

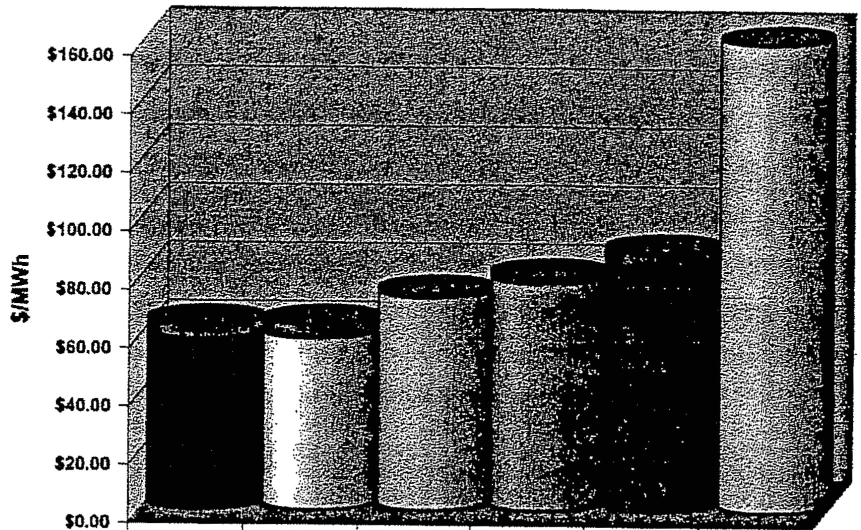
The overall economic difference between subcritical and supercritical PC technology is not material. The proposed BSPII Project will utilize supercritical PC technology in order to minimize emissions.

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

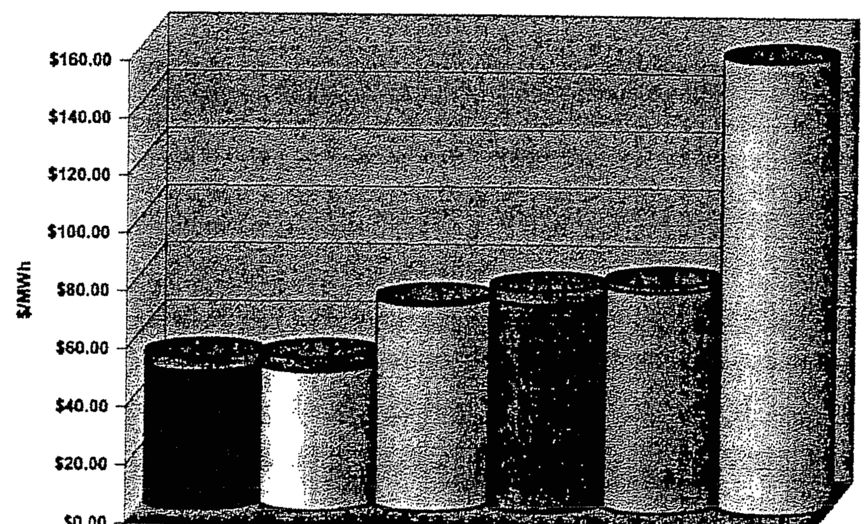
The Minnesota Public Utilities Commission has identified a range of values for a carbon dioxide externality of $0.35/ton to $3.64/ton. The inclusion of a carbon dioxide externality value, or imposition of a carbon tax, would cause an increase in the busbar cost of power for a new baseload resource. Figures 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 42×10^{-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 x 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 42×10^{-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 20×10^{-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™ 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™) 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
	\$1,300/ton NO_x (ozone season)
	\$35,000/lb Mercury
• Operating Assumptions:	
Overall Capacity Factor	88.0% for baseload comparison

5.3 FUEL COST FORECAST

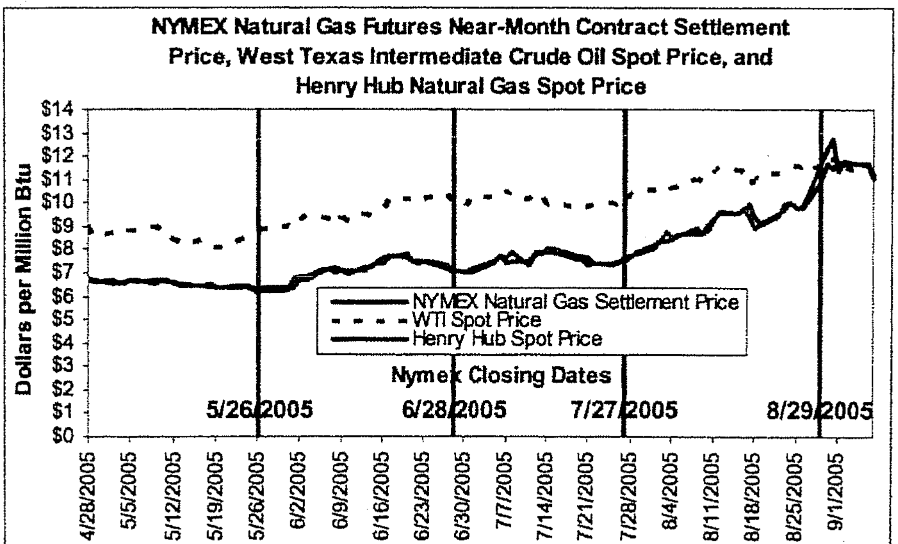
Table 5-1 presents the base case fuel cost assumptions used in the economic model analysis for each of the baseload technology alternatives. Detailed fuel cost forecasts are provided in Table 5-2.

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%

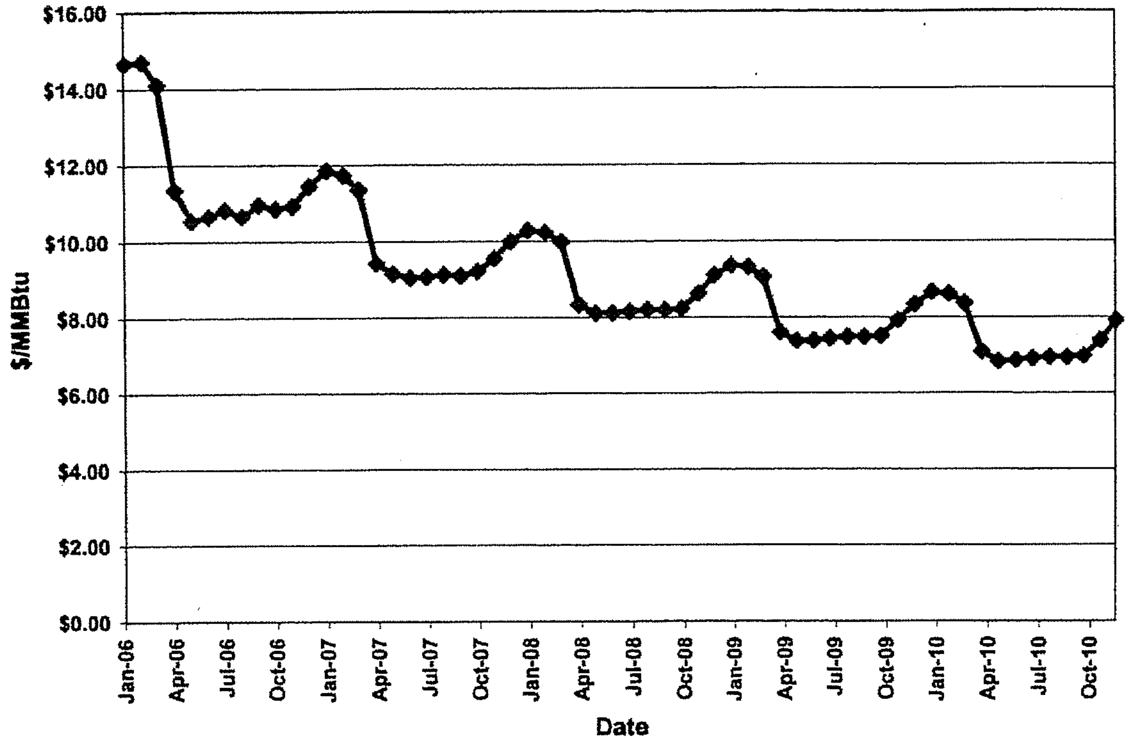
Note that the natural gas cost forecast of $7.00/MMBtu for 2011 is significantly lower than current 2005 natural gas cost pricing. Natural gas prices in 2005 have increased to near-record levels in the aftermath of Hurricane Katrina as exhibited in Figure 5-1. It is difficult to predict if natural gas 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
	Transportation	$ 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
I.B 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
	Transportation	$ 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
	Transportation	$ 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
	Transportation	$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
	Transportation	$ 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
I.B 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
	Transportation	$ 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	$ 3.87	$ 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
	Transportation	$ 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
	Transportation	$ 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

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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
	30 months for Biomass
	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
	30 months for Biomass
	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

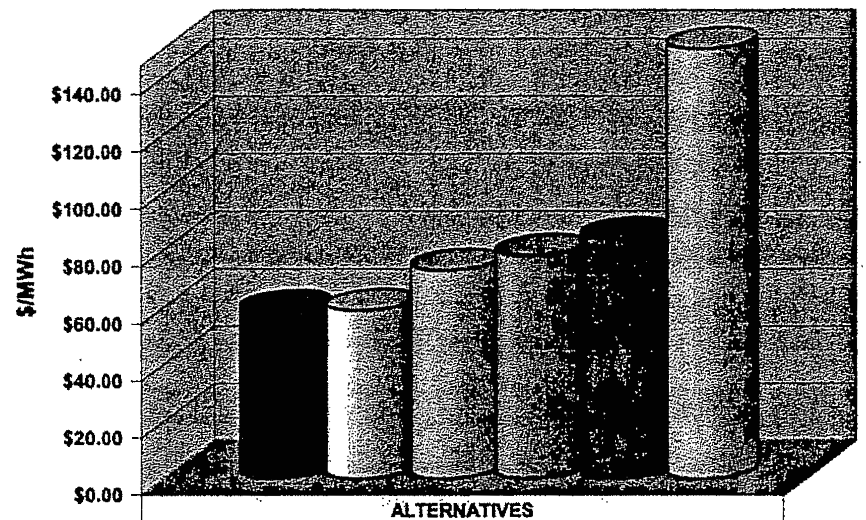
Note that the capital cost estimates presented in Table 4-2 are escalated to the midpoint of construction. The O&M estimates in Table 4-2 are presented in 2005 dollars.

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



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

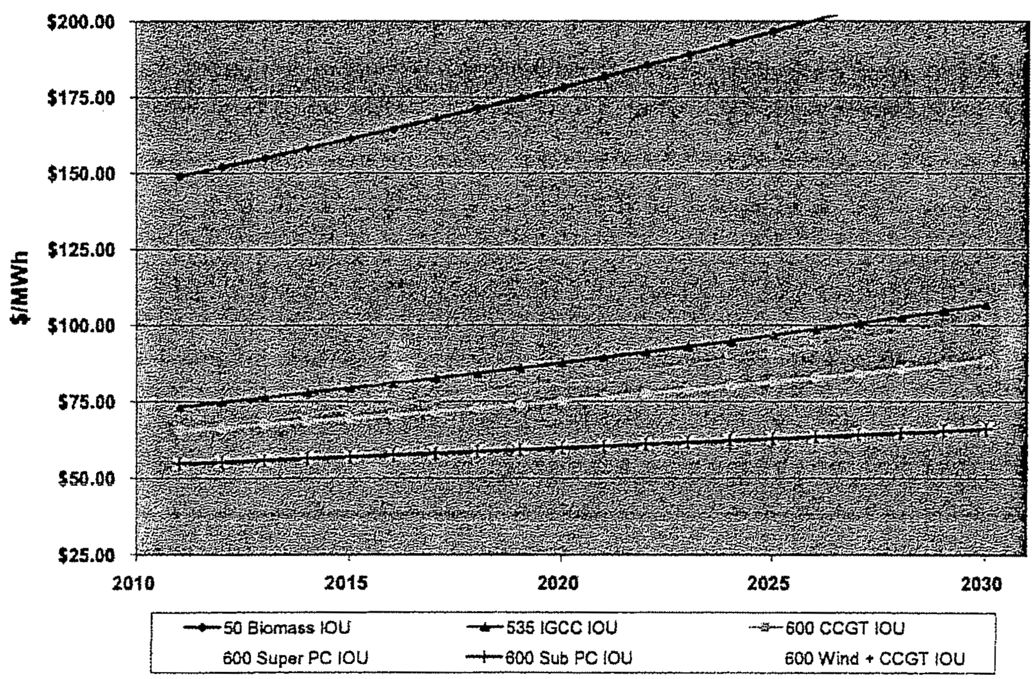
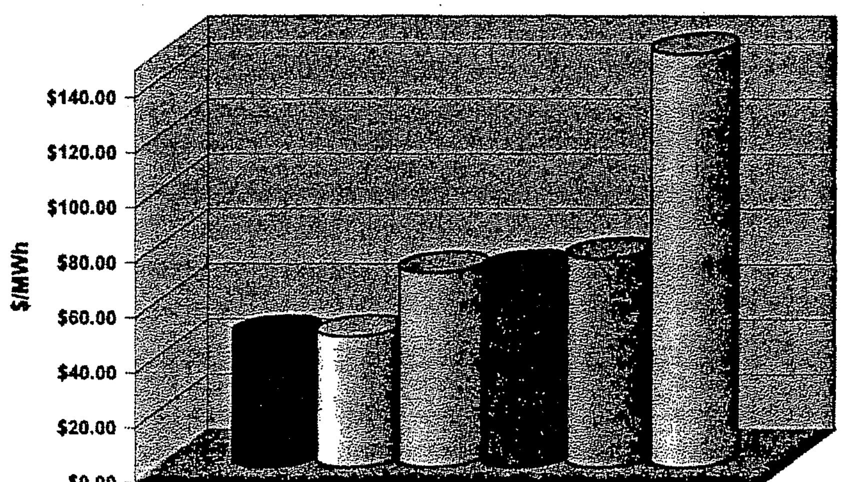


Figure 5-5 presents a graph of the resulting levelized busbar power costs for each of the baseload generation alternatives for a public power utility. Figure 5-5 was developed by preparing a project economic model for each of the alternatives under consideration. The busbar cost represents the levelized 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

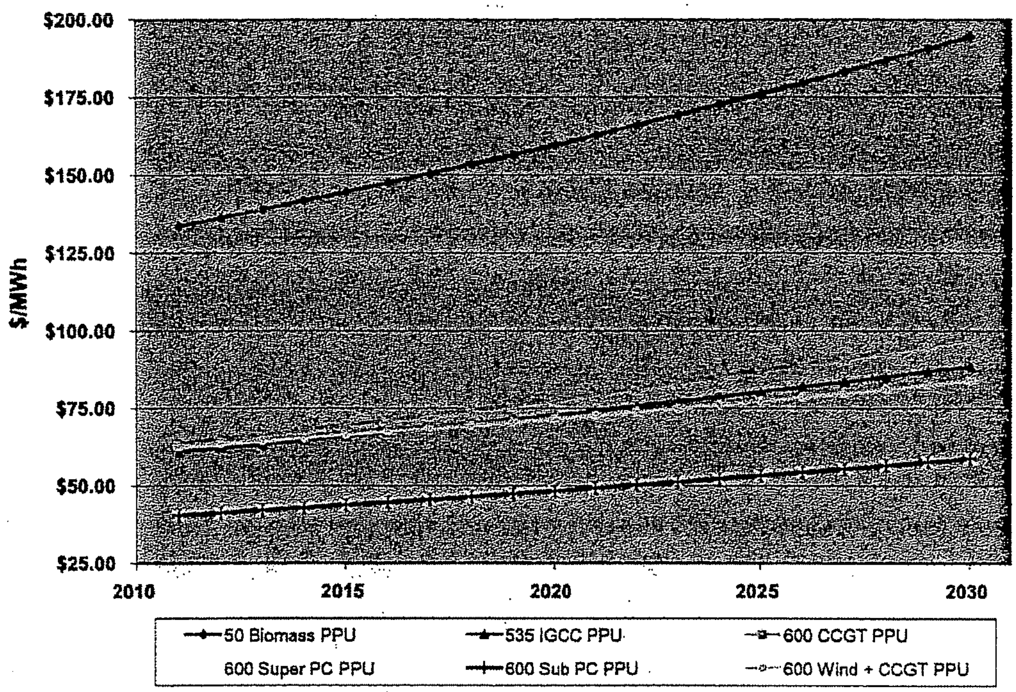


Table 5-3 provides the annual busbar cost for the first twenty years of operations for both an investor owned utility and a public power utility for each alternative.

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
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
	600 MW Sub PC	$54.63	$55.18	$55.73	$56.29	$56.85	$57.42	$57.99	$58.57	$59.16	$59.75
	600 MW CCGT + Wind	$65.63	$66.61	$67.62	$68.65	$69.70	$70.77	$71.88	$73.00	$74.15	$75.33
	600 MW CCGT	$66.67	$68.19	$69.75	$71.35	$72.99	$74.66	$76.37	$78.12	$79.90	$81.73
	535 MW IGCC	$73.19	$74.66	$76.15	$77.67	$79.22	$80.81	$82.43	$84.07	$85.76	$87.47
	50 MW Biomass	$148.87	$151.85	$154.88	$157.98	$161.14	$164.36	$167.65	$171.00	$174.42	$177.91
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
	600 MW Sub PC	$40.36	$41.17	$41.99	$42.83	$43.69	$44.56	$45.45	$46.36	$47.29	$48.24
	600 MW CCGT + Wind	$62.68	$63.60	$64.53	$65.49	$66.47	$67.47	$68.49	$69.54	$70.61	$71.71
	600 MW CCGT	$63.14	$64.58	$66.06	$67.57	$69.12	$70.71	$72.32	$73.98	$75.67	$77.41
	535 MW IGCC	$60.74	$61.96	$63.20	$64.46	$65.75	$67.06	$68.41	$69.77	$71.17	$72.59
	50 MW Biomass	$133.38	$136.05	$138.77	$141.54	$144.38	$147.26	$150.21	$153.21	$156.28	$159.40

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Investor Owned Utility	600 MW Super PC	$60.76	$61.37	$61.98	$62.60	$63.23	$63.86	$64.50	$65.14	$65.79	$66.45
	600 MW Sub PC	$60.35	$60.95	$61.56	$62.18	$62.80	$63.43	$64.06	$64.70	$65.35	$66.00
	600 MW CCGT + Wind	$76.53	$77.77	$79.03	$80.32	$81.63	$82.98	$84.36	$85.78	$87.22	$88.70
	600 MW CCGT	$83.61	$85.52	$87.48	$89.48	$91.53	$93.63	$95.77	$97.97	$100.21	$102.50
	535 MW IGCC	$89.22	$91.00	$92.82	$94.68	$96.57	$98.51	$100.48	$102.49	$104.54	$106.63
	50 MW Biomass	$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	$49.37	$50.36	$51.36	$52.39	$53.44	$54.51	$55.60	$56.71	$57.84	$59.00
	600 MW Sub PC	$49.20	$50.18	$51.19	$52.21	$53.26	$54.32	$55.41	$56.52	$57.65	$58.80
	600 MW CCGT + Wind	$72.83	$73.98	$75.15	$76.35	$77.58	$78.84	$80.12	$81.44	$82.78	$84.16
	600 MW CCGT	$79.18	$80.99	$82.85	$84.75	$86.69	$88.67	$90.70	$92.78	$94.90	$97.08
	535 MW IGCC	$74.04	$75.53	$77.04	$78.58	$80.15	$81.75	$83.39	$85.05	$86.75	$88.49
	50 MW Biomass	$162.59	$165.84	$169.16	$172.54	$175.99	$179.51	$183.11	$186.77	$190.50	$194.31

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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

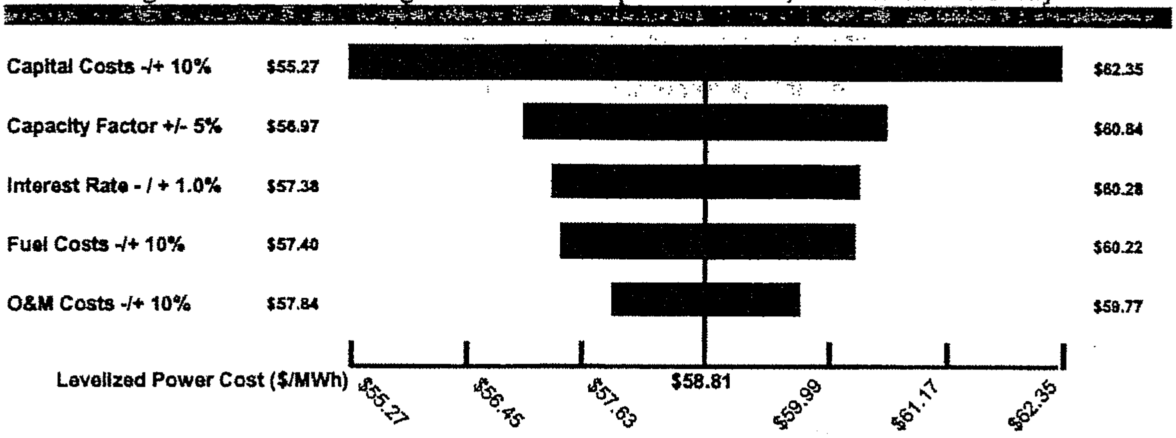


Figure 5-8: Tornado Diagram – 600 MW Wind Plus CCGT, Investor Owned Utility

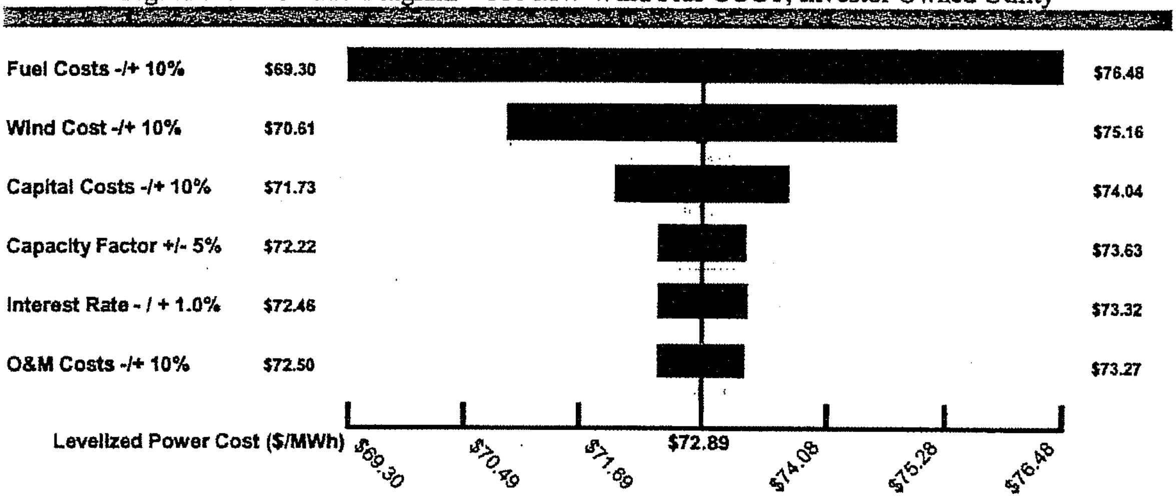


Figure 5-9: Tornado Diagram – 600 MW CCGT, Investor Owned Utility

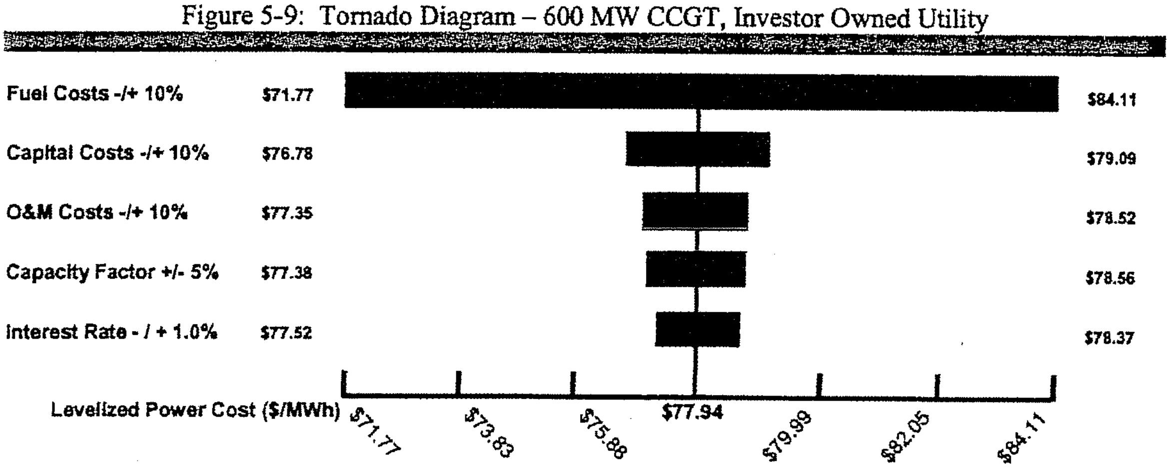


Figure 5-10: Tornado Diagram – 600 MW Supercritical Unit, Public Power

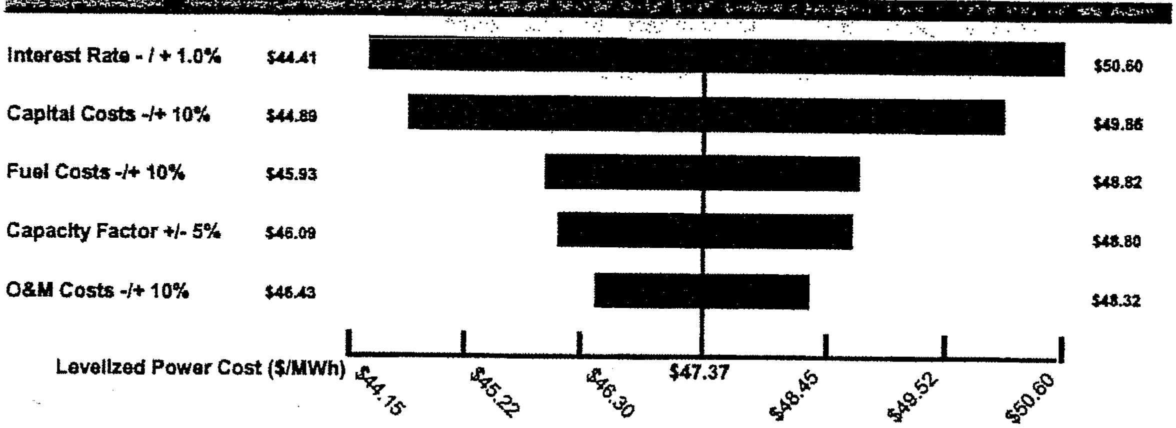


Figure 5-11: Tornado Diagram – 600 MW Wind Plus CCGT, Public Power

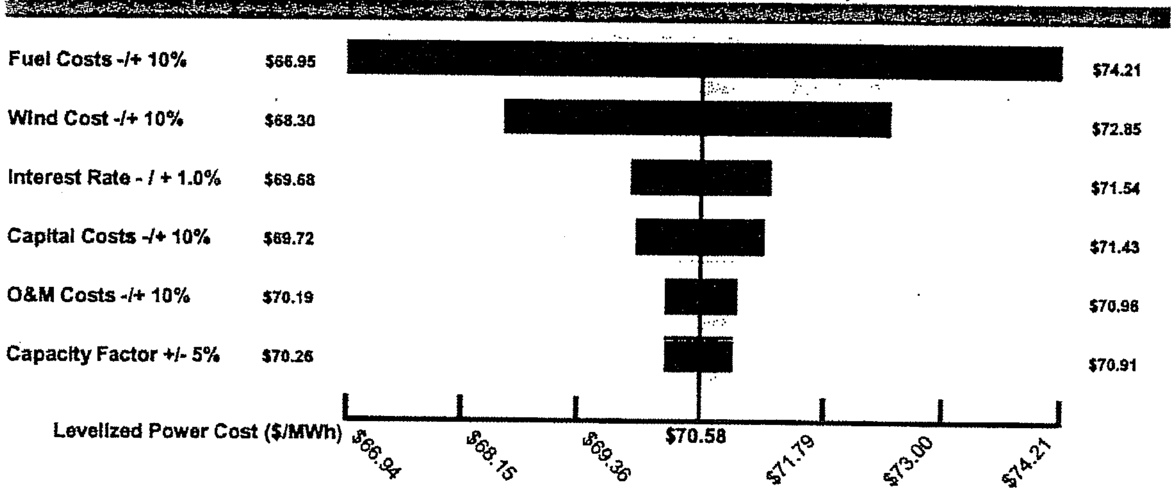
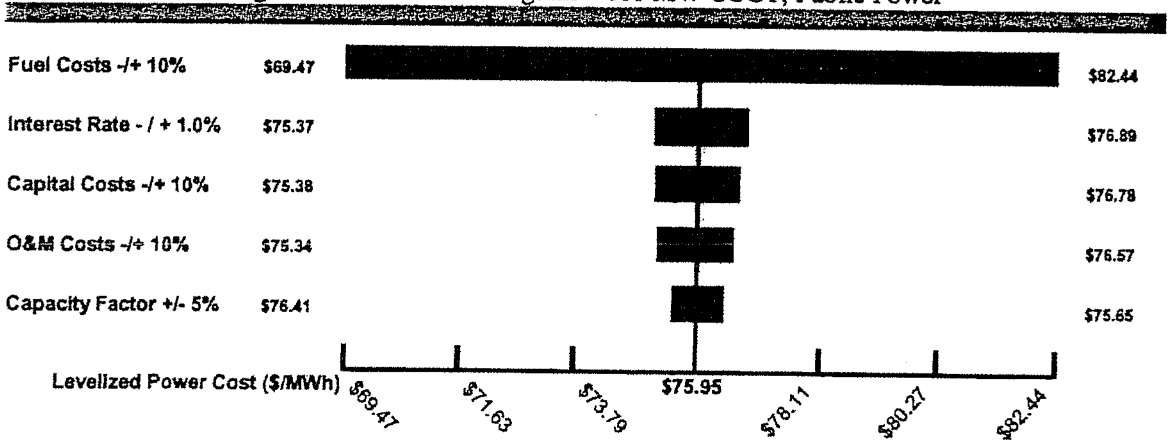


Figure 5-12: Tornado Diagram – 600 MW CCGT, Public Power



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

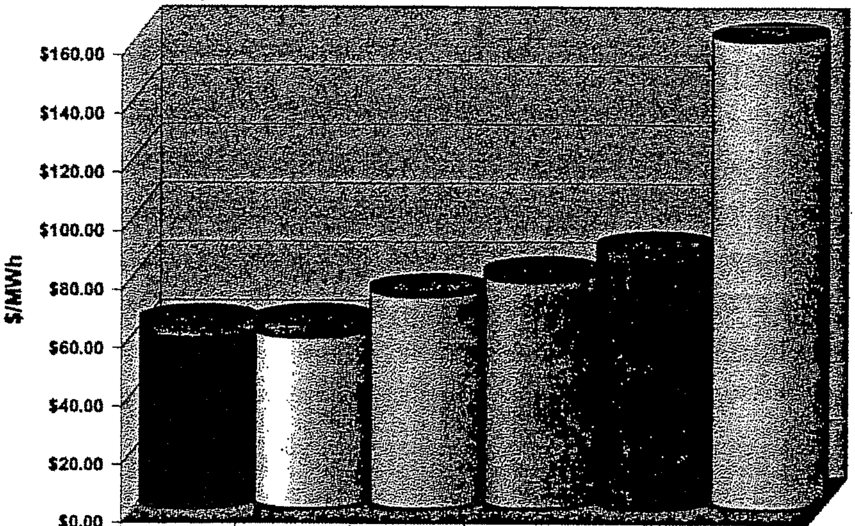
The emissions costs of the different baseload generation alternatives have been internalized in the economic model analysis. Each baseload generation alternative includes control technologies to meet expected BACT requirements, and emission allowance costs are incorporated for NO_x (ozone season), SO_2,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

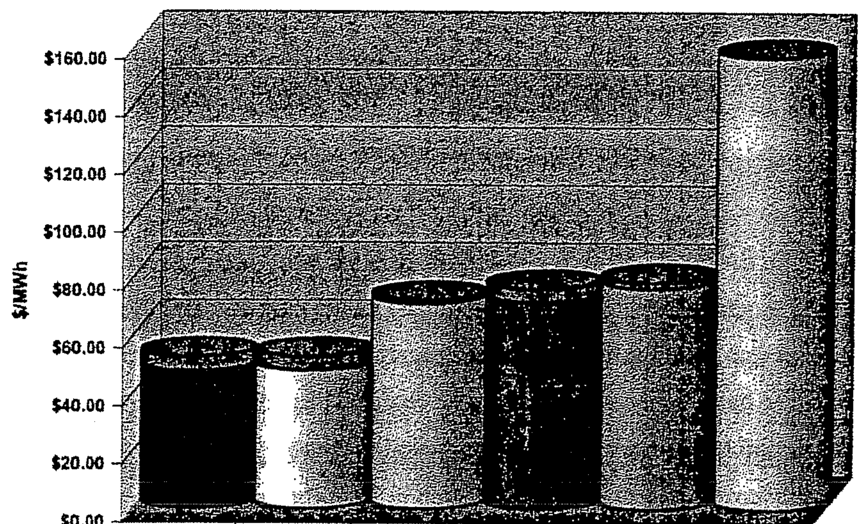
- PC Units 208 lbs/MMBtu
- CCGT Unit 110 lbs/MMBtu
- Wind Plus CCGT Unit 110 lbs/MMBut gas, 0 lbs/MMBtu wind
- IGCC Unit 200 lbs/MMBtu (capture and sequestration not included)
- Biomass Unit 0 lbs/MMBtu (assumes closed-loop system)

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.

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