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Revised Analysis of Baseload Generation Alternatives

Prepared for

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Big Stone Unit II

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Burns & McDonnell
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TABLE OF CONTENTS

UPDATED ECONOMIC EVALUATION OF BASELOAD GENERATION ALTERNATIVES

LIST OF TABLES

LIST OF FIGURES

UPDATED ECONOMIC EVALUATION OF BASELOAD GENERATION ALTERNATIVES

1.1 INTRODUCTION

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

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

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

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

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

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

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

The Study focuses on three alternatives:

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

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

1.2 SUMMARY OF GENERATION ALTERNATIVES

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

Table 1: Technology Summary

PROJECT TYPE	630 MW PC Supercritical Big Stone Unit II	500 MW Combined Cycle Greenfield	500 MW Combined Cycle + Wind [1]
Number of Gas Turbines	N/A	2	2
Number of Boilers/HRSGs	1	2	2
Number of Steam Turbines	1	1	1
Steam Cycle Type	Supercritical	Subcritical	Subcritical
Design Fuel	100% PRB	100% Natural Gas	100% Natural Gas
NOx Control	Low NOx Burners, SCR, OFA	Dry Low NOx Burners, SCR	Dry Low NOx Burners, SCR
SO2 Control	Wet Scrubber	N/A	N/A
Particulate Control	Baghouse	N/A	N/A
Ash Disposal	Landfill On Site	N/A	N/A
Net Plant Output, kW	630,000	500,000	500,000
Net Plant Heat Rate, Btu/kWh (HHV)	9,095	6,704	7,204
Capital Cost, $/kW (2012 COD) [2], [3]	$2,168	$749	$749
Fixed O&M Cost, $/kW-Yr (2006$) [4]	$10.11	$7.81	$7.81
Variable O&M Cost, $/MWh (2006$)	$2.23	$3.85	$3.85
Purchase Price of Wind (2012$)	N/A	N/A	$60.00
PROJECT TYPE	**630 MW PC Supercritical Big Stone Unit II**	**500 MW Combined Cycle Greenfield**	**500 MW Combined Cycle + Wind [1]**
NOx, lb/MMBtu	0.07	0.011	0.011
SO2, lb/MMBtu	0.10	< 0.0051	< 0.0051
CO2, lb/MMBtu	208	110	110
Hg, lb/MWh	$2.1^{\wedge}10^{-5}$	N/A	N/A

[1] Cost, performance, and emissions for CCGT component, assumed to operate at 48% capacity factor.
Non-firm wind energy assumed to be purchased at $60/MWh at equivalent energy to displace 40% CCGT capacity factor.
[2] Capital costs for BSII estimated as $1.366 billion for 630 MW net by Black & Veatch.
[3] Capital costs for CCGT based on B&V Study, $562/kW plus 20% Owner's Costs (2006$).
Escalated conservatively at 2.5% annually.
[4] Fixed O&M costs for BSII do not include property taxes and insurance, added subsequently in pro forma.

1.3 CCGT PLUS WIND

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

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

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

1.4 ECONOMIC ANALYSIS ASSUMPTIONS

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

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

- Operating Assumptions:

Overall Capacity Factor	88.0% for baseload comparison

1.5 FUEL COST FORECAST

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

Table 2: Fuel Cost Assumptions

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

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

1.6 FINANCING AND ECONOMIC ASSUMPTIONS

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

- Financing Assumptions (Investor Owned Utility):

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

Construction Financing	48 months for PC 24 months for CCGT

- Financing Assumptions (Public Power):

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

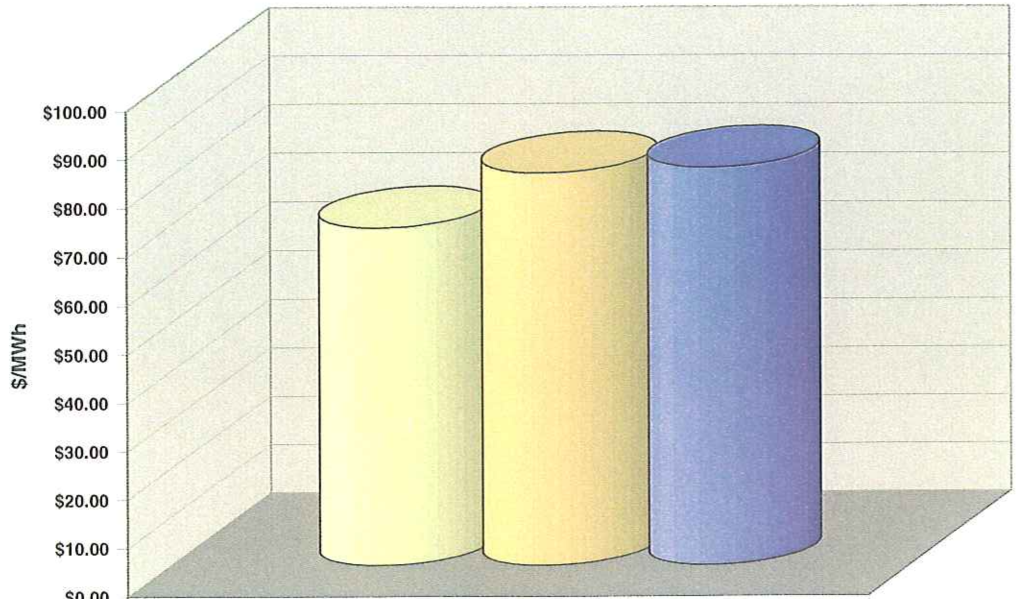
- Economic Assumptions:

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

1.7 SUMMARY OF ECONOMIC ANALYSIS

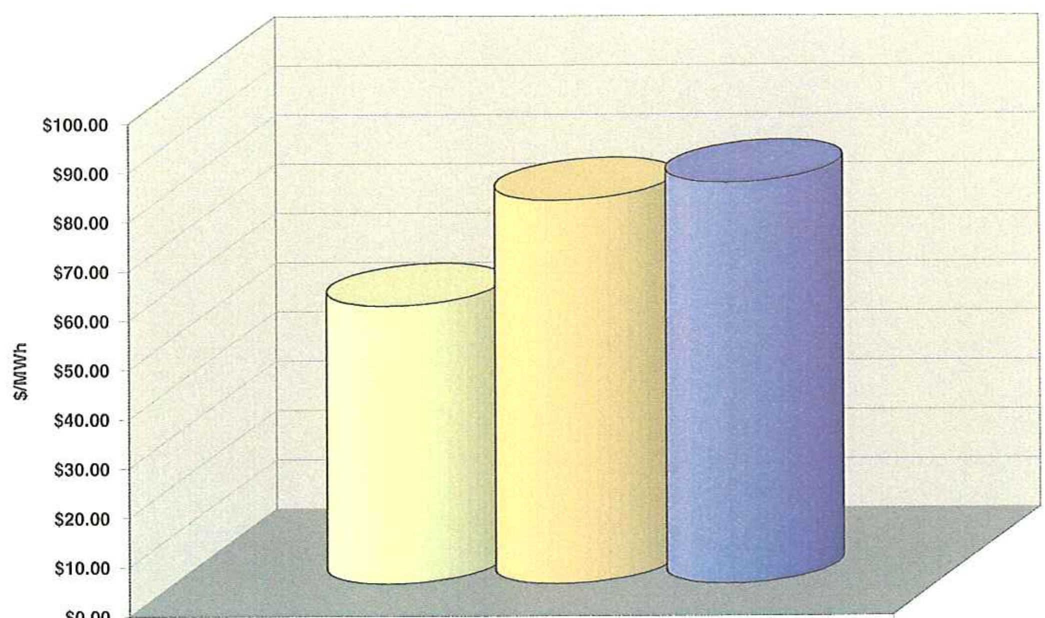
B&McD prepared an economic model analysis for each of the baseload generation alternatives based on the cost and performance estimates presented in Table 1. A 20-year economic analysis was prepared and the levelized busbar cost of each alternative was determined under two ownership structures: investor-owned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

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



630 BSII IOU	$69.62
500 CCGT +Wind IOU	$80.78
500 CCGT IOU	$81.89

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



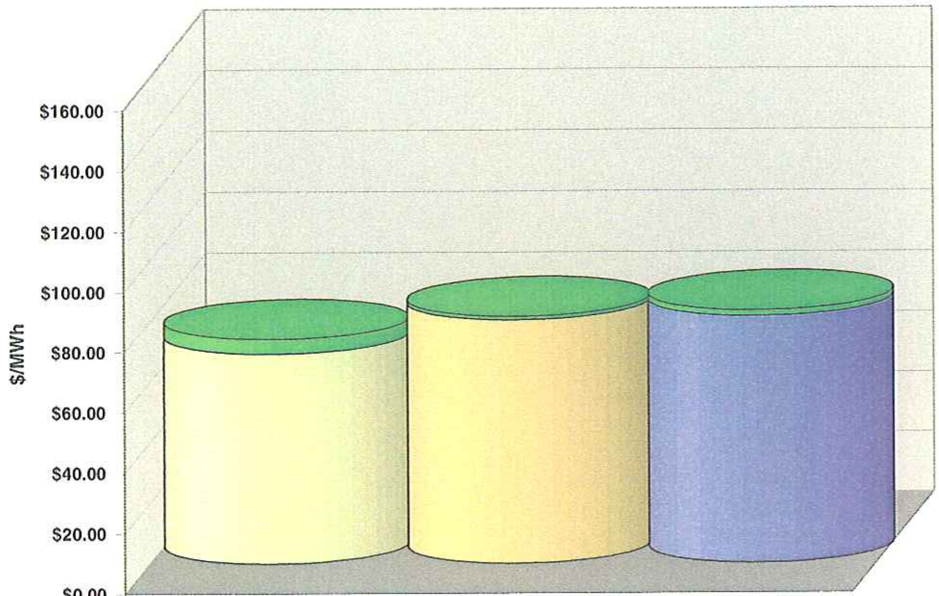
630 BSII PPU	$56.38
500 CCGT +Wind PPU	$77.77
500 CCGT PPU	$81.30

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

1.8 SUMMARY OF CARBON COST SCENARIOS

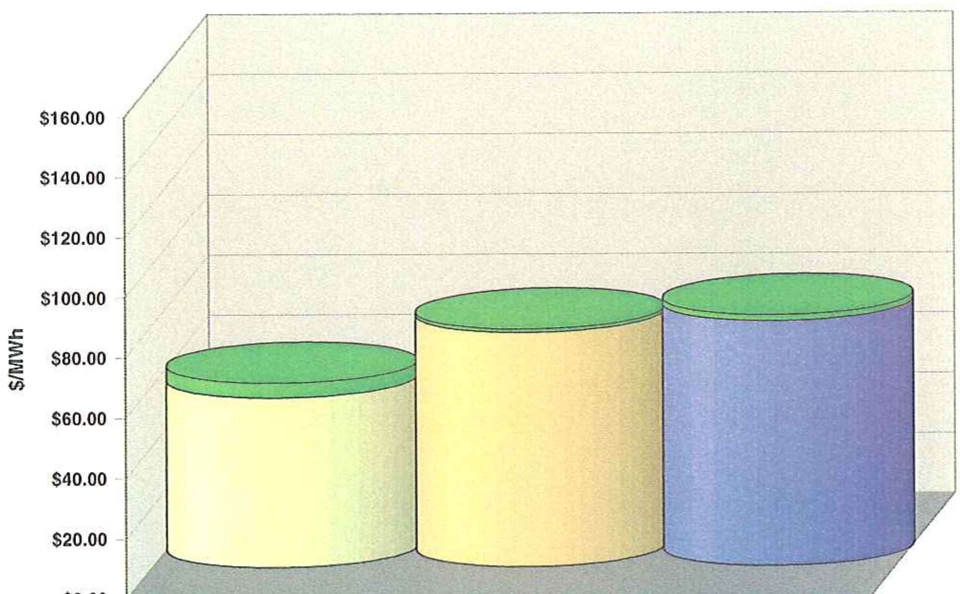
The Minnesota Public Utilities Commission has identified a range of values for a carbon dioxide environmental cost value of \$0.35/ton to \$3.64/ton. The inclusion of a carbon dioxide environmental cost value (through imposition of a carbon tax or otherwise) would cause an increase in the busbar cost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

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



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

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



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

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

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

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

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

1.9 CONCLUSIONS

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

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

1.10 PTC SENSITIVITY

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

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

1.10.1 Investor-Owned Utility PTC and Carbon Cost Sensitivity Results

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

1.10.2 Public Power Utility PTC and Carbon Cost Sensitivity Results

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

1.11 STATEMENT OF LIMITATIONS

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

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