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UPDATED ECONOMIC EVALUATION OF BASELOAD GENERATION ALTERNATIVES

prepared for

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1.1 INTRODUCTION

Burns and McDonnell (B&McD) previously prepared a number of pro forma economic analyses of baseload generation technology alternatives for the Otter Tail Power Company (OTPCo) Big Stone Unit II (BSII or Project). A twenty-year economic model analysis was prepared based on the estimated capital costs, performance, fuel costs, emissions, and operating costs of each baseload generation alternative. The economic model analyses of each baseload generation alternative resulted in a levelized busbar cost that could be compared against the other alternatives.

Recently, several inputs to the economic models were updated, and the models were rerun. This evaluation presents the changes to the inputs and the new pro forma model results.

In addition, the BSII participant group is considering downsizing the Project size as an alternative to remarketing available capacity to new participants. Supercritical pulverized coal (PC) units of 580 MW and 500 MW have been added to this updated analysis.

1.2 UPDATED ECONOMIC ANALYSIS ASSUMPTIONS

The following provides the economic analysis assumptions utilized in the original economic model analysis compared to the assumptions utilized in the updated economic model analysis.

Commercial Online Date	Updated Input	2006 Input
• Project COD (all options)	2013	2012
Coal Unit Capital Costs [1]	Updated Input	2006 Input
• 630 MW Supercritical PC (BSII)	$1.496 billion	$1.366 billion
• 580 MW Supercritical PC	$1.412 billion	Not Modeled
• 500 MW Supercritical PC	$1.272 billion	Not Modeled

[1] PC unit costs are presented in time of construction (nominal) dollars.

Gas Unit Costs[2]	Updated Input	2006 Input
• 500 MW CCGT Plant (2006$)	$674.4/kW	$674.4/kW

[2] 2x1 GE 7FA CCGT capital cost estimated by B&V and escalated to COD at 5.0%.

Fuel Cost Forecast	Updated Input	2006 Input
• PRB Coal Cost (2010$)	$1.74/MMBtu	$1.71/MMBtu
• PRB Coal Escalation Rate	3.5% per annum	2.9% per annum
• Natural Gas Cost	$8.31/MMBtu (2012$)	$7.60/MMBtu (2011$)
• Natural Gas Escalation Rate	Unchanged	3.0% per annum

Purchased Wind Power Cost [3]	Updated Input	2006 Input
• Levelized Cost – With PTC (2006 $)	$40.00/MWh	$40.00/MWh
• Levelized Cost – No PTC	+$20.00/MWh	$60.00/MWh

[3] Purchase cost of non-firm wind estimated by B&McD and escalated to COD at 5.0%.

CO_2 Emissions Environmental Costs	Updated Input	2006 Input
• CO_2 Emissions Cost	$9.00/ton (2007$)	$3.64/ton (2006$)
• CO_2 Emissions Escalation Rate	Levelized	2.5% per annum

Operating Assumptions	Updated Input	2006 Input
• Overall Capacity Factor	Unchanged	88.0%

1.3 CAPITAL STRUCTURE AND ECONOMIC ASSUMPTIONS

The following financing and economic assumptions were utilized in the initial economic model analysis and remain unchanged. They are listed again herein for a comprehensive description of assumptions. The economic model analyses were prepared under two distinct ownership and cost of capital structures: investor owned utility (IOU) and public power utility (PPU).

Note that each of the BSII 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	48 months for PC
	24 months for CCGT

Financing Assumptions (Public Power Utility)

• Interest Rate	6.0%
• Term	30 years
• Debt/Equity Percentage	100%/0%
• Return on Equity	N/A
• Construction Financing	48 months for PC and IGCC
• 24 months for CCGT	

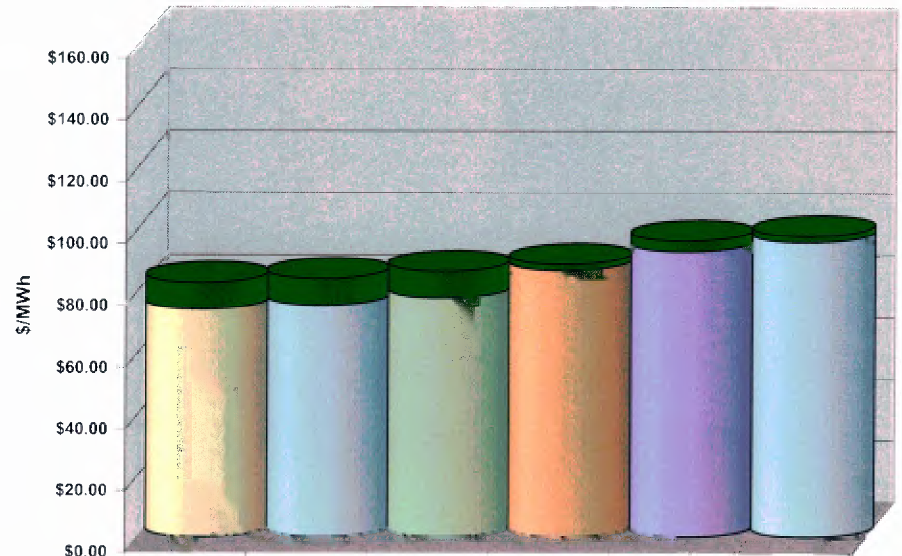
Economic Assumptions

• 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

1.4 SUMMARY OF ECONOMIC ANALYSIS

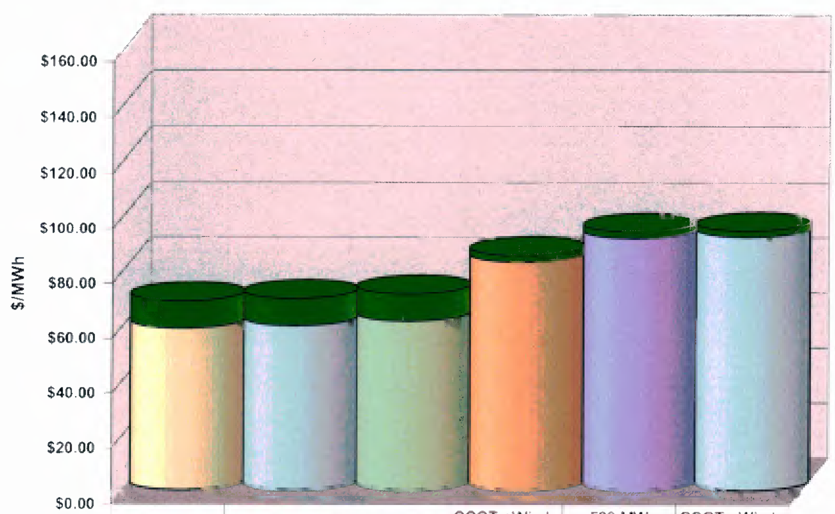
B&McD prepared an updated economic model analysis for each of the baseload generation alternatives based on the updated inputs presented in the previous sections. A 20-year economic analysis was prepared and the levelized busbar cost of each alternative was determined under two ownership structures: investor-owned utility (IOU) and public power utility (PPU). Figures 1 and 2 present graphs showing the 20-year levelized busbar power costs in 2013$ for each of the baseload generation alternatives under both investor owned utility and public power utility ownership.

Figure 1: Levelized Busbar Costs (2013$) – Investor Owned Utility



	630 MW BSII	580 MW BSII	500 MW BSII	CCGT +Wind - With PTC	500 MW CCGT	CCGT +Wind - No PTC
Total Busbar Cost	$82.61	$83.89	$86.27	$88.55	$96.09	$97.64
Carbon Tax	$8.63	$8.63	$8.63	$2.00	$3.41	$2.00
Busbar Cost w/o Carbon Tax	$73.98	$75.26	$77.65	$86.55	$92.68	$95.64

Figure 2: Levelized Busbar Costs (2013$) – Public Power Utility



	630 MW BSII	580 MW BSII	500 MW BSII	CCGT +Wind - With PTC	500 MW CCGT	CCGT +Wind - No PTC
Total Busbar Cost	$68.62	$69.55	$71.30	$85.29	$94.03	$94.38
Carbon Tax	$9.92	$9.92	$9.92	$2.37	$2.54	$2.37
Busbar Cost w/o Carbon Tax	$58.70	$59.63	$61.38	$82.92	$91.49	$92.01

As indicated in Figures 1 and 2, the inclusion of a carbon environmental cost levelized value of \$9.00/ton increases the levelized busbar costs of all the alternatives, but does not change the relative economics of the baseload alternatives.

The three supercritical PC units remain cost-effective, even accounting for higher costs associated with declining economy of scale on the unit size from 630 MW to 500 MW.

1.4.1 Investor Owned Utility Results

The break-even carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost is approximately \$12.10/ton for the investor owned utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately \$89.25/MWh, which is an increase of 15 percent compared to the base case 500 MW BSII cost of \$77.65/MWh for an IOU participant. The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost is approximately \$15.30/ton for the IOU structure. This would increase the levelized busbar cost of both alternatives to approximately \$89.95/MWh, which is an increase of 20 percent compared to the base case 580 MW BSII cost of \$77.65/MWh for an IOU participant.

The break-even carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (without PTC) levelized busbar cost is approximately \$24.40/ton for the investor owned utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately \$101.05/MWh, which is an increase of 30 percent compared to the base case 500 MW BSII cost of \$77.65/MWh for an IOU participant. The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (without PTC) levelized busbar cost is approximately \$27.70/ton for the IOU ownership structure. This would increase the levelized busbar cost of both alternatives to approximately \$101.80/MWh, which is an increase of 35 percent compared to the base case 580 MW BSII cost of \$77.65/MWh for an IOU participant.

1.4.2 Public Power Utility Results

The break-even carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost is approximately

$25.70/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $89.70/MWh, which is an increase of 46 percent compared to the base case 500 MW BSII cost of $61.38/MWh for a public power participant. The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost is approximately $27.80/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $90.27/MWh, which is an increase of 51 percent compared to the base case 580 MW BSII cost of $61.38/MWh for a public power participant.

The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (without PTC) levelized busbar cost is approximately $36.60/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $101.70/MWh, which is an increase of 66 percent compared to the base case 500 MW BSII cost of $61.38/MWh for a public power participant. The break-even carbon dioxide environmental cost value to equalize the 580 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (without PTC) levelized busbar cost is approximately $38.70/ton for the public power utility ownership structure. This would increase the levelized busbar cost of both alternatives to approximately $102.28/MWh, which is an increase of 71 percent compared to the base case 580 MW BSII cost of $61.38/MWh for a public power participant.

Overall, inclusion of a $9.00/ton CO_2 environmental cost value in the evaluation did not impact the baseload generation economic results irrespective of whether the PTC is extended, or whether the BSII unit size is decreased by moderate levels.

Further, the analysis relies on a conservative assumption regarding the purchase price of non-firm wind energy. The estimated 2006 purchase price of $40.00/MWh (with PTC) has been escalated 5.0% annually, implying a 2007 purchase price of $42.50/MWh. However, due to significant cost increases in wind turbine-generator units and general construction and commodity cost escalation that has impacted all generation resources, B&McD's clients are currently pricing new wind farm developments at $50/MWh or higher.

1.5 NATURAL GAS COST SENSITIVITY

The primary driver for these updated results is the increase in natural gas costs. In the analysis prepared in September 2006, NYMEX futures for natural gas supply were $7.20/MMBtu in 2011. In October 2007, the MYMEX futures price for natural gas supply in 2012 had increased to $7.91/MMBtu. In both cases, a conservative transportation cost of $0.40/MMBtu was added.

Natural gas prices remain high and highly volatile. Therefore, it is appropriate to test the results against the potential that natural gas prices will prove to be higher than predicted. As an example, Attachment A from a recent Energy Information Administration report outlines the delivered cost of natural gas to electric utilities relative to wellhead prices. As indicated, the average differential in the US in 2006 was $0.67/MMBtu ($7.09/MMBtu - $6.42/MMBtu). Year- to-date 2007 indicates a differential of $1.25/MMBtu. B&McD is reflecting a conservative $0.40/MMBtu transportation component for a northern Midwest generic location. Actual transportation and balancing costs could be significantly higher.

In addition, if a carbon tax or CO_2 allowance program were to be implemented in the United States, there would likely be an increase in natural gas based power generation. This would increase the demand for natural gas, and potentially further drive up the price of natural gas relative to coal resources. As a sensitivity analysis, levelized busbar costs were calculated for the CCGT plus Wind cases assuming a $0.50/MMBtu and a $1.00/MMBtu increase in natural gas costs.

Under an investor owned utility ownership structure, if the price of natural gas increased by $0.50/MMBtu, the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $91.04/MWh. This would increase the breakeven carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost to approximately $15.40/ton for the investor owned utility ownership structure. If the price of natural gas increased by $1.00/MMBtu the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $93.55/MWh. This would increase the breakeven carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost to approximately $18.80/ton for the investor owned utility ownership structure.

Under a public power utility ownership structure, if the price of natural gas increased by $0.50/MMBtu, the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $87.78/MWh. This would increase the breakeven carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost to approximately $28.70/ton for the public power utility ownership structure. If the price of natural gas increased by $1.00/MMBtu, the levelized busbar cost of the CCGT plus Wind (with PTC) would increase to approximately $90.43/MWh. This would increase the breakeven carbon dioxide environmental cost value to equalize the 500 MW supercritical PC BSII unit levelized busbar cost with the CCGT plus Wind (with PTC) levelized busbar cost to approximately $31.60/ton for the public power utility ownership structure.

1.6 CONCLUSIONS

This 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 and volatile cost of natural gas fuel makes it uneconomical for baseload dispatch.
- The CCGT plus Wind case reflects the next lowest cost baseload energy resource combination, but is 12 percent higher cost for the IOU utilities and 35 percent higher cost for the public power utilities compared to the 500 MW Big Stone II alternative, if the PTC is renewed. Plus, the CCGT resource is not renewable.
- If the PTC is not renewed, The CCGT plus Wind case is 23 percent higher cost for the IOU utilities and 50 percent higher cost for the public power utilities compared to the 500 MW Big Stone II alternative.
- Inclusion of a carbon environmental cost value in the evaluation of $9.00/ton did not change the results and was primarily offset by continued escalation in natural gas costs. In addition, the transportation component assumed for natural gas is conservative, as is the purchase cost for non-firm wind energy utilized in the analysis.
- If a carbon tax or CO_2 allowance program were imposed, the price of natural gas would likely increase, therefore, further increasing the levelized busbar cost of natural gas based alternatives.

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, fuel costs, 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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Table 3. Selected National Average Natural Gas Prices, 2002-2007
(Dollars per Thousand Cubic Feet)

Year and Month	Wellhead Price[a]	City Gate Price	Delivered to Consumers: Residential Price	Commercial: Price	Commercial: % of Total[b]	Industrial: Price	Industrial: % of Total[b]	Electric Power Price[c]
2002 Annual Average	**2.95**	**4.12**	**7.89**	**6.63**	**77.38**	**4.02**	**22.70**	**3.68**
2003 Annual Average	**4.88**	**5.85**	**9.63**	**8.40**	**78.24**	**5.89**	**22.12**	**5.57**
2004 Annual Average	**5.46**	**6.65**	**10.75**	**9.43**	**77.97**	**6.53**	**23.66**	**6.11**
2005								
January	5.80	7.05	11.03	10.23	85.22	7.05	24.67	6.72
February	5.74	7.09	11.02	10.08	85.48	7.14	24.11	6.42
March	5.95	7.24	11.00	10.16	84.96	7.11	24.37	6.84
April	6.58	7.79	12.02	10.49	83.21	7.71	23.71	7.27
May	6.24	7.51	12.88	10.55	80.14	7.19	23.97	6.83
June	6.09	7.30	13.92	10.41	78.98	6.92	23.44	7.08
July	6.71	7.68	14.99	10.73	76.59	7.40	24.21	7.58
August	6.48	8.20	15.66	11.19	77.19	7.99	24.31	8.67
September	8.96	10.26	16.70	12.82	75.78	10.19	22.95	11.01
October	10.35	12.16	16.56	14.62	79.59	12.07	22.97	11.85
November	9.91	11.57	15.78	15.11	81.83	12.13	23.20	9.87
December	9.08	10.77	14.75	14.32	84.48	11.17	23.44	11.28
Annual Average	**7.33**	**8.67**	**12.84**	**11.59**	**82.71**	**8.56**	**23.81**	**8.48**
2006								
January	[E]8.66	10.75	14.94	14.11	83.79	10.85	[R]22.33	9.09
February	[E]7.28	9.27	14.00	13.00	84.03	9.31	[R]22.15	7.99
March	[E]6.52	8.74	13.20	12.01	83.87	8.24	[R]22.30	7.35
April	[E]6.59	8.28	13.28	11.51	80.84	7.94	[R]21.91	7.31
May	[E]6.19	7.94	14.40	11.54	78.37	7.65	[R]22.32	6.87
June	[E]5.80	7.29	15.03	11.03	75.65	6.91	[R]21.85	6.67
July	[E]5.82	7.27	15.69	10.92	74.35	6.80	22.03	6.67
August	[E]6.51	7.96	16.17	11.14	72.12	7.39	[R]22.36	7.52
September	[E]5.51	7.58	15.69	11.10	74.30	7.23	[R]20.58	6.32
October	[E]5.03	6.34	12.57	10.05	77.05	5.63	[R]21.24	5.75
November	[E]6.43	8.39	12.47	11.05	80.06	7.79	[R]21.32	7.48
December	[E]6.65	8.66	12.53	11.57	82.35	8.26	[R]21.88	7.56
Annual Average	**[E]6.42**	**8.54**	**13.75**	**11.97**	**80.57**	**7.89**	**[R]21.86**	**7.09**
2007								
January	[E]5.92	7.86	12.08	11.12	82.99	7.36	22.24	7.04
February	[E]6.66	8.60	12.13	11.23	83.68	8.27	21.99	8.17
March	[E]6.56	8.81	12.85	11.82	83.25	8.47	21.22	7.64
April	[RE]6.84	8.17	13.28	11.54	80.88	8.17	21.43	7.76
May	[E]6.98	8.33	14.59	11.58	77.83	8.14	22.43	7.96
June	[E]6.86	8.39	16.22	11.91	73.52	8.01	22.96	[R]7.80
July	[E]6.19	7.94	16.65	11.63	73.83	7.58	22.03	NA
August	[E]5.90	7.45	16.85	11.16	72.00	6.58	22.26	NA
2007 YTD[d]	**[E]6.49**	**8.25**	**13.05**	**11.44**	**80.67**	**7.82**	**22.06**	**7.74**
2006 YTD[d]	**[E]6.67**	**8.86**	**14.19**	**12.39**	**81.10**	**8.19**	**22.16**	**7.38**
2005 YTD[d]	**6.20**	**7.36**	**11.70**	**10.33**	**83.13**	**7.31**	**24.12**	**6.89**

[a] See Appendix A, Explanatory Note 9, for discussion of wellhead prices.
[b] Percentage of total deliveries represented by onsystem sales (see Figure 6). See Table 23 for State data.
[c] The electric power sector comprises electricity-only and combined-heat-and-power plants within the NAICS 22 category whose primary business is to sell electricity, or electricity and heat, to the public. Beginning in 2002, data include nonregulated members of the electric power sector.
[d] Year-to-date price represents months for which price information is available in the current year. The electric power sector year-to-date price is two months behind those of wellhead, city gate, residential, commercial and industrial.
[E] Estimated data.
[NA] Not available.
[RE] Revised estimated data.

Notes: Data for 2002 through 2005 are final. All other data are preliminary unless otherwise indicated. Geographic coverage is the 50 States and the District of Columbia.

Sources: 2002-2005: Energy Information Administration (EIA), *Natural Gas Annual 2005*. January 2006 through current month: Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers"; Form EIA-910, "Monthly Natural Gas Marketer Survey"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Federal Energy Regulatory Commission (FERC), Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; and EIA estimates.