

BOSTON PACIFIC COMPANY, INC.

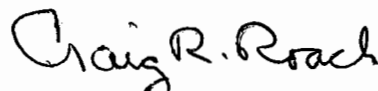
October 21, 2008

Mr. Burl Haar
Minnesota Public Utilities Commission
121 7th Place East, #350
St. Paul MN 55101

Dear Mr. Haar:

Enclosed please find one copy of Boston Pacific Company, Inc.'s Report entitled *Responding to Commission Inquiries on Emissions Costs, Construction Costs and Fuel Costs*. Boston Pacific very much appreciates the opportunity to submit this Report to the Commission.

Sincerely,


Craig R. Roach


Frank Mossburg

Enclosure

**REPORT RESPONDING TO THE COMMISSION'S INQUIRIES ON
EMISSIONS COSTS, CONSTRUCTION COSTS, AND FUEL COSTS**

Presented to

THE MINNESOTA PUBLIC UTILITIES COMMISSION

by

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1 **I. BACKGROUND AND SUMMARY**

2
3 **A. Background**

4
5 This Docket involves an application for a Certificate of Need for transmission
6 lines in Western Minnesota by five applicants: Otter Tail Power Company, Montana-
7 Dakota Utilities, Missouri River Energy Services, Central Minnesota Municipal Power
8 Agency and Heartland Consumers Power District (collectively, “the Applicants”).¹
9 Importantly, the transmission is tied to the construction of a new coal-fired power plant
10 on the site of the existing Big Stone facility near Milbank, South Dakota; the new plant is
11 referred to as Big Stone II.

12
13 The Applicants’ choice of Big Stone II over other resource options is based on the
14 results of capacity expansion and other modeling analyses. Intervenors have criticized
15 the Applicants’ analyses for, among other things, (a) failing to analyze an appropriate
16 range of costs to comply with future carbon dioxide (CO₂) emissions regulations that may
17 be imposed as a result of Federal legislation, (b) using inaccurate construction cost
18 estimates for all resource options and (c) using inappropriate fuel price forecasts.

19

1 ¹ Certificate of Need Application for Transmission Lines in Western Minnesota in MPUC Dkt No. CN-05-619 (September 30, 2005). The initial application included seven applicants; however, now there are only five.

1 Given these criticisms, Boston Pacific Company, Inc.² was engaged by the
2 Minnesota Public Utilities Commission (“the Commission”) to write a report addressing
3 three questions related to the analyses in the Big Stone II application. The Commission
4 specified the three questions as follows:

- 5
- 6 a. How passage of the greenhouse-gas regulation bills introduced in Congress to
7 date would affect the cost of energy and power generated by a supercritical,
8 pulverized-coal-fired plant such as Big Stone II?
- 9
- 10 b. What are the likely construction costs for a supercritical pulverized-coal-fired
11 plant such as Big Stone II, constructed on a brownfield site, with an in-service
12 date of approximately 2014-2015? In addition, what are the likely construction
13 costs for an alternative wind generation system, with natural-gas-fired back-up,
14 with a comparable capacity factor and in-service date? Finally, what are the
15 likely construction costs for a natural-gas-fired plant with a comparable capacity
16 factor and in-service date?
- 17
- 18 c. What are the likely delivered costs of natural gas and coal for power plants in the
19 North Dakota/South Dakota/Minnesota area over the first fifteen years of the

² Boston Pacific Company, Inc. was chosen for this effort, in part, because of its substantial experience as an Independent Evaluator or Monitor for power procurements across the country. These include recent engagements for procurements of unit contingent power in, for example, Oregon, Oklahoma, and the Virgin Islands as well as procurements for full requirements power in Delaware, the District of Columbia, Illinois, Maryland and New Jersey. Our experience also includes service as expert witnesses on resource decisions before State Commissions and FERC as well as power project development across the U.S. and in two dozen other countries around the world. Resumes and lists of testimony and publications are attached for the two principal authors of this report.

1 operation of any of the three generation systems described in (b), assuming the
2 passage of climate-change regulation?³

3
4 Before presenting our answers to the Commission's three questions, it is
5 important to state the context in which we believe the Commission's decision to approve
6 or reject the Certificate of Need must be made. At the outset, note that, all across the
7 U.S., State Commissions and the utilities they regulate are making important decisions
8 about how the electricity needs of ratepayers will be met in the future. Minnesota is not
9 alone. We take as a given that the goal for this decision-making is to get the best deal
10 possible for ratepayers, and that, today, the deal must be defined in all its dimensions –
11 price, risk, reliability, and environmental performance. Furthermore, to serve this goal,
12 Commissions must meet two significant challenges: (a) manage uncertainty (or risk) and
13 (b) promote new technologies.

14
15 With respect to managing risk, all decision makers face at least three big
16 uncertainties as reflected in the three questions Boston Pacific was asked to address: (a)
17 What will be the nature and cost of CO₂ (and other greenhouse gas) regulations? (b) What
18 will be the construction costs for all the resource alternatives (demand-and-supply-side)?
19 and (c) What will be the path for natural gas and coal prices? Given these uncertainties,
20 no one can predict the future with precision so all resource options must be assessed
21 under a range of futures to assure ratepayers will get the best deal possible no matter how
22 the future unfolds. (To actually manage risks, Boston Pacific would go beyond assessing

³ Minnesota Public Utilities Commission, *Request for Proposals* at p 1.

1 risk to actually assigning it to a party able to do something about it, but assignment of
2 risk does not appear to be an explicit issue in this proceeding.)

3
4 As to promoting new technologies, it is clear that just about everyone points to
5 new technologies (demand- and supply-side) as needed to meet our overall goals. For
6 example, if we want to stabilize prices or improve environmental performance, it is often
7 said new technologies are needed. It is important here for the Commission to explicitly
8 consider the effect of its decision as well as its decision-making process on new
9 technologies; the decision-making process must invite and accommodate new players
10 with new technologies.

11
12 And, finally, we note that complicating matters further is the fact that the Federal
13 Government has been slow to enact a national energy policy, leaving these decisions up
14 to individual States. This increases the chances that neighboring States can make
15 substantially different decisions on what is the best deal for ratepayers.

16 17 **B. Summary of Findings**

18
19 This report fits into the broader context explicitly because it focuses on whether
20 risk was appropriately assessed. That is, do the Applicants appropriately assess risk by
21 using a valid range of inputs regarding CO₂ emission costs, construction costs, and fuel
22 prices?

1 In general we believe the range of emissions, construction, and fuel price inputs
2 used in the Applicants' analyses were not appropriate; put another way, they were out of
3 line with current "best practices" resource selection methodologies. Specifically, with
4 respect to emissions costs, we found the Applicants' use of a \$0 to \$9 per ton CO₂ tax,⁴
5 without escalation over time, to be far lower than the ranges justified for resource
6 decisions today; the later use of a \$30 per ton tax was a good step forward but did not go
7 far enough.⁵

8
9 We recommend analyzing resource choices under four different levels of CO₂
10 taxes: \$8, \$20, \$40 and \$60 per ton of CO₂, starting in 2012, and escalating with inflation
11 thereafter. As detailed in the body of the report, our recommendation is supported by (a)
12 recent market prices in greenhouse gas auctions worldwide, (b) a variety of cost estimates
13 for proposed congressional legislation, (c) estimates of the CO₂ tax levels needed to
14 actually reduce emission levels, and (d) the ranges of estimates used in a sample of actual
15 Integrated Resource Plans (IRPs).

16
17 With respect to new construction costs, we understand that the Applicants' latest
18 analysis used an estimate of \$2,545 per kW for the installed costs for Big Stone II.⁶ This
19 is below even the low end of our estimate of the possible range of installed costs for a

⁴ Supplemental Prefiled Testimony of James Heidell in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Heidell") at p 11, lines 5-7, Supplemental Prefiled Testimony of Bryan Morlock in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Morlock") at p 16, lines 1-17, Supplemental Prefiled Testimony of J.P. Schumacher in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Schumacher") at p 23, lines 4-18, Supplemental Prefiled Testimony of Robert L. Davis in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Davis") at p 14, line 5 – p 15, line 5.

⁵ Prefiled Rebuttal Testimony of Jeffrey J. Greig in MPUC Dkt No. CN-05-619 (January 16, 2008) (hereinafter as "Greig January 16, 2008") at p 5 line 17 – p 6 line 1.

⁶ Supplemental Prefiled Testimony of Mark Rolfes in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Rolfes") at p 4.

1 new coal-fired facility, which we would estimate to be from \$2,600 per kW to \$3,000 per
2 kW; these are installed costs in nominal dollars for a new brownfield plant without
3 interest during construction (IDC) or transmission integration costs.

4
5 For new gas-fired combined cycle facilities, the Applicants used \$1,200 per kW to
6 \$1,795 per kW as their estimate of installed costs.⁷ This is either at or above the high end
7 of our estimates of the appropriate range of costs for new combined cycle facilities, even
8 accounting for some Applicant's inclusion of transmission and IDC costs. In our view,
9 the appropriate range is \$1,000 to \$1,200 per kW. For gas-fired combustion turbines our
10 expected range of costs is \$800 per kW to \$1,100 per kW. The Applicants used a similar
11 range of \$870 to \$1,098 per kW. Finally, the Applicants' cost estimates for wind turbines
12 (\$1,810 to \$2,270 per kW) are generally in the right region, we would use a range of
13 \$2,000 to \$2,200 per kW.

14
15 Equally important, while different Applicants had different construction cost
16 estimates as discussed above, there was no effort to test a range of assumptions about
17 construction costs in a unified capacity expansion model analysis to see if the resource
18 decision changed with changes in those costs. This point is especially important in a case
19 like this where we are not dealing with competitively-bid, pay-for-performance price
20 offers or detailed fixed-price engineering, procurement, and construction (EPC) contracts.
21 Here, the Applicants offer only an estimated cost so that ratepayers bear the risks that
22 costs will be higher.

⁷ Heidell at p 17, Davis at Ex – 117 A, Schumacher at p 4. Note that Heidell and Schumacher appear to have included IDC and transmission integration costs. Davis did not include IDC and it is unclear if his estimates included transmission. The current capital cost numbers used in Morlock's analysis are unclear.

1

2 With respect to fuel price forecasts, we believe that the Applicants’ initial or
3 “base case” estimates for coal and natural gas prices are reasonable given current market
4 conditions and projections by other sources. However, we believe that the Applicants
5 differed from a “best practice” analysis by not testing their results against a wide range of
6 prices for natural gas. Based on historical volatility in natural gas futures, we would
7 recommend that a range of natural gas prices be tested equal to plus and minus 25%
8 around the base 2012 price of \$8 per MMBtu.

9

10

11 **II. ADDRESSING THE COMMISSION’S THREE QUESTIONS**

12

13 **A. Greenhouse Gas Regulation**

14

15 The first question we were asked to address is how the passage of greenhouse gas
16 regulation bills introduced in Congress would affect the cost of power generated at a
17 coal-fired energy facility like Big Stone II. It is generally agreed that there will be some
18 form of regulation of greenhouse gas emissions in the future, and that regulation will
19 increase the cost of emitting CO₂. This is especially important to the resource choice
20 here because a coal-fired power plant such as Big Stone II will emit about twice the
21 amount of CO₂ of a new gas-fired combined-cycle facility. Moreover, renewable
22 resources such as wind emit no CO₂. Therefore, any resource choice must take this
23 potential cost into account.

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The Applicants did attempt to examine the effect of future CO₂ costs in two ways. First in their capacity expansion modeling Applicants looked at resource selection using a range of costs from zero to \$9 per ton of CO₂.⁸ Notably, this \$9 per ton cost was not escalated, meaning that it decreased in real (inflation-adjusted) terms over time.⁹ Applicants’ witness Greig also presented a “busbar” analysis comparing Big Stone II’s likely annual cost (i.e. fuel costs, fixed and variable operating and maintenance charges, capital charges and emissions costs) versus that of a new gas-fired combined cycle and wind market purchases with a combined-cycle backup.¹⁰ He reports that he examined CO₂ cost levels ranging from \$4 to \$30 per ton; again, we understand these were not escalated over time.¹¹

While most agree that there will be some form of greenhouse gas regulation, they also agree it is quite difficult to predict an exact cost for CO₂ emissions in the future. To judge whether the Applicants assessed a reasonable range of costs, Boston Pacific reviewed three categories of information:

1. Market Prices for CO₂

⁸ Heidell at p 11, lines 5-7, Morlock at p 16, lines 1-17, Schumacher at p 23, lines 4-18, Davis at p 14, line 5 – p 15, line 5.
⁹ Ibid.
¹⁰ Supplemental Prefiled Testimony of Jeffrey J. Greig in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as “Greig November 13, 2007”) at p 2, lines 1 - 11.
¹¹ Greig January 16, 2008 at p 5 line 17 – p 6 line 1.

1 The first category of information is current CO₂ allowance prices as traded in the
2 open market. The purpose of examining this data is to see what parties are actually
3 paying for allowances. CO₂ allowances were first issued and traded on a large scale in
4 Europe. On October 17, 2008, the price for allowances for a December 2008 settlement
5 date was priced at 21.68 Euros or about US \$29 per ton on the European Climate
6 Exchange.¹² The Exchange offers contracts through December 2014. Currently, prices
7 for settlement increase as the years progress. On October 17th, contract prices for a
8 December 2014 settlement date were 27.27 Euros or about US \$37 per ton.¹³

9
10 In addition, a group of ten U.S. states, under the banner of the Regional
11 Greenhouse Gas Initiative (RGGI) held the first U.S.-based auction for CO₂ allowances
12 on September 25, 2008.¹⁴ The market clearing price for that auction, in which six of the
13 ten states participated, was \$3.07 per ton.¹⁵ This value is somewhat in line with futures
14 prices on the Chicago Climate Exchange, where carbon emission allowances traded at
15 about \$2 per ton during the week of the RGGI Auction.¹⁶

16
17 The large discrepancy between European and American numbers is thought to be
18 chiefly due to the basic forces of supply and demand; specifically, as the number of
19 allowances offered for sale falls relative to the demand, prices will be higher. This

¹² European Climate Exchange: (http://www.europeanclimateexchange.com/default_flash.asp).
Translated to USD using market EUR/USD exchange rate as listed on October 17, 2008 by x-rates.com.
<http://www.x-rates.com/cgi-bin/hlookup.cgi>.

¹³ Ibid.

¹⁴ Regional Greenhouse Gas Initiative "RGGI": (<http://rggi.org/co2-auctions/results>).

¹⁵ Ibid.

¹⁶ Chicago Climate Exchange: (<http://www.chicagoclimatex.com/market/data/daily.jsf>). Data retrieved for
September 24, 2008.

dynamic was present in the early years of European climate markets, where too many allowances were issued, relative to the need, and the price of allowances collapsed.¹⁷

2. Cost Estimates for Proposed Legislation

A second category of information which we can examine is studies which attempt to estimate the cost impact of various pieces of proposed U.S. climate change legislation. Several key studies attempt to predict the effects of the Lieberman-Warner Climate Security Act of 2007 (S. 2191). Lieberman-Warner would establish a “cap and trade” system for emissions allowances.¹⁸ Some allowances would be distributed and others auctioned off. The bill, with an amendment by Senator Boxer, was last considered by the Senate in June, and is still worth examining because (a) it is the only climate change bill to be reported out of committee, (b) it may return in some form at a later date, and (c) the “cap and trade” system with offset provisions and gradually declining annual emissions targets that it establishes is present in almost every other proposed climate change bill. For instance, the recent draft of the Dingell-Boucher bill also features a “cap and trade” system with a goal of reducing CO₂ emissions to 80% below 2005 levels by 2050.¹⁹

¹⁷ International Financial Services London (IFSL), *Carbon Markets & Emissions Trading* (June 2007) at p 3.

¹⁸ Lieberman-Warner Climate Security Act of 2007 as introduced in the Senate on October 18, 2007 at Sec. 3 at p 8.

¹⁹ VanNess Feldman Attorneys at Law, *Issue Alert: Representatives Dingell and Boucher Release Discussion Draft of Climate Change Legislation* (October 9, 2008) at p 1.

1 Studies of the impact of Lieberman-Warner show a broad range of possible cost
2 impacts. Table One (attached for pullout) shows the predicted allowance price for the
3 “base case” analyses of several important studies of the Lieberman-Warner bill.

4
5 As is evident from Table One, estimates of the cost of emissions allowances under
6 this legislation vary greatly, ranging from (a) \$21 to \$48 a ton in 2015 and (b) from \$46
7 to \$86 a ton by 2030. This divergence in results is driven by differences in models and
8 the assumptions used within each study. With this divergence there is certainly no one
9 “right” allowance price estimate. However, an examination of these studies reveals to us
10 what some of the key drivers of emission prices may be in the future.

11
12 First, differences in overall economic growth projections make a big difference.
13 Lieberman-Warner, as other bills do, has certain emission targets for each year. If
14 economic growth slows, there will be less pressure on generators to buy (or use)
15 allowances since there will be less pressure to run power plants as demand growth slows.
16 Because of this, studies which use more recent growth outlooks, which are less
17 optimistic, generally show lower allowance prices. For example, the EPA’s study was
18 based on an economic outlook from the EIA in 2006. Altering the inputs to roughly
19 match 2008 EIA “baseline” emissions projections results in allowance prices of about
20 \$22-\$35 per ton in 2015, about \$5 to \$7 lower than the two EPA estimates in Table One
21 which reflect the 2006 economic growth projections.²⁰

22

²⁰ Environmental Protection Agency (EPA), *EPA Analysis of the Lieberman-Warner Climate Securities Act of 2008* (March 14, 2008) (hereinafter as “EPA March 14, 2008”) at p 17 and 27.

1 Second, projections about the growth of nuclear power and renewables make a
2 large difference. The more that utilities can depend on new nuclear and renewable
3 technologies to fill their generation needs the less they will need allowances to support
4 coal-, oil- and gas-fired generation. In the EIA Core analysis, 268 GW of new nuclear
5 and 112 GW of new renewables construction is assumed.²¹ If that construction pace is
6 not achieved, and there is slower deployment of carbon capture and sequestration (CCS),
7 the price of an allowance in 2020 moves from \$30 to \$44 per ton according to EIA.²²

8
9 Third, the cost of and ability to use offsets instead of buying allowances is a major
10 factor. Lieberman-Warner would have allowed up to 30% of emissions to be offset
11 through a combination of domestic and foreign offsets. Restrictions on offset use will
12 increase prices. For example, EPA's analysis found that removing offsets increased the
13 price of an allowance from \$51 in 2020 to \$98.²³ When EIA removed just international
14 offsets, the 2020 price of an allowance rose by \$12 (from \$30 to \$42).²⁴

15
16 While we focus here on Lieberman-Warner, since it progressed farther than other
17 legislation and had more high-profile studies conducted on it, it is also worth mentioning
18 that analysis of other climate change bills has shown a different range of results. The
19 EPA's analysis of S. 280 (Lieberman-McCain) and S. 1766 (Bingaman-Specter) showed
20 allowance prices around \$12-\$15 in 2015, rising to \$25-\$32 in 2030.²⁵ The generally

²¹ Energy Information Administration, *EIA Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008) (hereinafter as "EIA April 2008") at p 24.

²² Ibid. at Table ES2.

²³ EPA March 14, 2008 at p 27.

²⁴ EIA April 2008 at Table 3.

²⁵ Environmental Protection Agency (EPA), *EPA Analysis of The Climate Stewardship and Innovation Act of 2007* (July 16, 2007) (hereinafter as "EPA July 16, 2007") at p 24. Environmental Protection Agency

1 lower prices in these bills were due, in part, to the higher emissions caps in those bills
2 combined with safety-valve prices for allowances.

3
4 Other studies have attempted to predict allowance prices by changing the
5 question. Instead of asking “what will this legislation do to allowance prices” they ask
6 “what would the price of allowances have to be in order to reduce emissions?” A 2006
7 report on the economics of climate change by the head of the British Government
8 Economic Service (the “Stern Report”) stated that reducing emissions to an acceptable
9 level would result in a marginal cost of abatement of around \$25 to \$30 per ton of CO₂
10 emitted.²⁶ A recent report by McKinsey suggested a number of ways in which important
11 reductions in emissions could be made, using an upper-end cost of \$50 as a target price.²⁷

12 13 **3. Estimates in Integrated Resource Plans**

14
15 Clearly, the estimates discussed above show that there is no one “right” number
16 when it comes to greenhouse gas emissions costs. How, then, are utilities supposed to
17 make decisions about resource acquisition? In our opinion, the best practice is to analyze
18 resource choices over a variety of emissions costs, with the goal of selecting resources
19 that deliver low-cost supply under a range of emissions regulations. The low end of the
20 range can be set around \$8, beginning in 2012, reflecting a relatively low-cost regime.
21 The high end can be set at \$60 a ton, reflecting a bill with tighter emissions caps along

(EPA), *EPA Analysis of the Low Carbon Economy Act of 2007* (January 15, 2008) (hereinafter as “EPA January 15, 2008”) at p 33.

²⁶ Sir Nicholas Stern, *The Economics of Climate Change: The Stern Review* (October 30, 2006) at p 304.

²⁷ McKinsey and Company, *Reducing U. S. Greenhouse Gas Emissions: How Much at What Cost?* (December 2007) at p xii.

1 with adverse outcomes such as limited development of new nuclear and renewable
2 generation and limited ability to use offsets. Mid-range cases of \$20 and \$40 per ton
3 should be examined as well. All costs should be escalated with inflation each year after
4 2012 and should be modeled as a tax. Emissions costs are typically modeled as a tax to
5 all generation, because each bill has differences in allowance distribution among
6 resources and among free allowances and auctions. Moreover, “free” allowances have an
7 opportunity cost equal to the market price.

8
9 Boston Pacific’s recommended approach also is supported by a review of a
10 sample of the latest Integrated Resource Plans (IRPs) from utilities around the country.
11 In each of these plans the utility is trying to address the same key questions as in this
12 proceeding: that is, what resources should we pursue given this uncertainty about
13 greenhouse gas regulations? Note that IRPs are not just theoretical exercises. Ideally, for
14 the sake of transparency, a utility will use the exact same analysis in a subsequent
15 competitive procurement when evaluating actual offers, whether the bids were vetted
16 through independent negotiations or competitive procurement.

17
18 Table Two (attached as pull out) shows the levels of emissions costs used in a
19 sample of publicly available IRPs and presentations. It is not meant to be an exhaustive
20 list, but is simply presented to show the general range of costs up for consideration.
21 Looking at Table Two we can see that there is, again, a wide range of costs estimated,
22 with the low end of the range set around zero to \$10 per ton beginning in 2010-2012
23 timeframe. The higher end is at \$55 per ton. There also are several in-between cases

1 using from \$20 to \$40 per ton. Note that almost all of the costs escalate at some rate,
2 typically roughly that of inflation or a bit more, year to year.

4 **4. Conclusion**

6 By only using estimates of up to \$9 a ton (or even \$30), unescalated, the
7 Applicants have not performed what we would consider an appropriate (“best practices”)
8 analysis of emissions cost risk. Furthermore, the “busbar” analysis does not adequately
9 serve the purpose of examining potential resource choices against changes in emissions
10 costs. This risk should be measured within the context of a capacity expansion model,
11 which will look at the effect of emissions costs on the utilities’ entire fleet over a long-
12 term horizon and select the best options for filling the utilities’ need; the busbar analysis
13 is a stand-alone analysis which does not consider how the facility in question would
14 operate within the utility’s system.

16 Resource choice must be assessed over a range of CO₂ taxes because future
17 emissions costs will depend on a variety of factors from (a) the emissions targets in
18 Federal Legislation to (b) the costs and availability of offsets to (c) the growth of nuclear
19 and renewable sources of generation. We believe the best practice would be to test
20 resource selection at \$8, \$20, \$40 and \$60 per ton of CO₂, starting in 2012 and escalating
21 at inflation thereafter. The goal of these analyses will be to identify, if possible, a
22 portfolio of resources that deliver low cost supply to ratepayers under a variety of

1 greenhouse gas regimes. At a minimum, such an analysis will reveal the breakpoints;
2 that is, what level of CO₂ tax switch the choice from one resource to another.

3 4 **B. Construction Costs**

5
6 The second question we have been asked to address deals with the construction
7 costs for new supercritical coal-fired plants like Big Stone II. We also were asked to
8 provide input regarding construction costs for new gas-fired combined cycle and
9 combustion turbine facilities as well as new wind generation. This input is important
10 because the construction cost of various technologies is a major driver in choosing which
11 resource to pursue.

12 13 **1. Our Judgment on Construction Costs**

14
15 It is true, as has been mentioned often in this proceeding, that construction costs
16 for new generation are rapidly escalating due to run ups in commodity prices (e.g. steel)
17 and increased demand for specialized labor and equipment. According to the IHS CERA
18 Power Capital Costs Index (PCCI), which measures the construction costs of new
19 facilities, costs for building new power plants have more than doubled since 2000 and
20 have risen 69 percent since 2005 alone.²⁸ We have seen this effect in our own work as
21 monitors for unit-contingent baseload RFPs. Bidders have had great difficulty obtaining
22 fixed-price commitments from engineering, procurement, and construction (EPC)

²⁸ IHS, *Construction Costs for New Power Plants Continue to Escalate: IHS CERA Power Capital Costs Index* (May 27, 2008) at <http://energy.ihs.com/News/Press-Releases/2008/IHS-CERA-Power-Capital-Costs-Index.htm>.

1 contractors. Because of ever-escalating construction costs, some RFPs now allow
2 bidders utilizing new generation to tie their capacity prices to changes in broad market
3 indices such as the Consumer Price Index (CPI) or the Producer Price Index (PPI) for
4 metals during the financing or construction phases of project development.

5
6 The capital cost for Big Stone II, according to Applicants' witness Rolfes, is
7 \$2,545 per kW for the smallest possible potential size (500 MW).²⁹ This number is in
8 nominal dollars and does not include transmission and interest during construction. This
9 number is based on a 2006 Black and Veatch estimate, escalated by 6% per year to
10 account for delays in construction and scaled to reflect the smaller plant design.³⁰

11
12 Estimates of capital costs for other resources vary among the four Applicants'
13 planners who utilized capacity expansion modeling.³¹ Capital cost estimates for new
14 natural-gas fired combined cycle units range from \$1,200 to \$1,795 per kW.³² Those for
15 new natural-gas fired combustion turbine units range from \$870 to \$1,098 per kW.³³ And
16 capital costs estimates for new wind turbine construction range from \$1,810 to \$2,270 per
17 kW.³⁴

²⁹ Rolfes at p 4.

³⁰ Ibid. at p 4-5.

³¹ Heartland did not use capacity expansion modeling, see, Supplemental Prefiled Testimony of John Knofczynski in MPUC Dkt No. CN-05-619 (November 13, 2007) (hereinafter as "Knofczynski") at p 6.

³² Heidell at p 17, Davis at Ex – 117 A, Schumacher at p 4. Note that Heidell and Schumacher appear to have included IDC and transmission integration costs. Davis did not include IDC and it is unclear if his estimates included transmission. The current capital cost numbers used in Morlock's analysis are unclear.

³³ Ibid.

³⁴ Ibid.

1 With respect to the Applicants' installed cost estimate of \$2,545 per kW, based on
2 our experience, we would conclude that it is below the low end of the spectrum for a
3 plant like Big Stone II. We would expect the facility to have installed cost somewhere in
4 the \$2,600 to \$3,000 per kW range (in nominal dollars, excluding interest during
5 construction and transmission upgrades). In contrast, the Applicants' ranges of estimates
6 for gas-fired combined cycle generation costs (\$1,200 to \$1,795 per kW) appears to be
7 above the likely range, even adjusting for the fact that some Applicants included
8 transmission upgrades and interest during construction costs in their numbers. We would
9 place the construction costs of a new combined cycle unit (again, in nominal dollars with
10 no interest during construction and no transmission upgrades) at \$1,000 to \$1,200 per
11 kW. For a combustion turbine, the Applicants' estimates of \$870 to \$1,098 per kW are
12 more in line with our estimate of \$800 to \$1,100 per kW. Similarly, the Applicants' cost
13 estimates for wind turbines (\$1,810 to \$2,270 per kW) are generally in the right region,
14 we would place the range at about \$2,000 to \$2,200 per kW. Again, our CT and wind
15 estimates are in nominal dollars and do not include IDC or transmission upgrades.

16 17 **2. Estimates From a Sample of IRPs**

18
19 Our judgments on the right range of installed cost to use are generally supported
20 by a review of current, publicly available utility IRPs. Again, these IRPs are useful
21 because utilities are attempting to address the same decision on resource choice that we
22 are faced with today. Most IRPs show what the utility believes to be the installed capital
23 costs plus the operating cost of different types of new generation. Table Three (attached

1 as pullout) presents, for a select group of recent IRPs and IRP update presentations, the
2 estimated installed cost for each technology as well as the year's dollar for the estimate.

3
4 From Table Three we can see the simple average estimate of installed cost (a) for
5 a combined cycle plant is \$1,008/kW, (b) for a combustion turbine it is \$971 per kW, (c)
6 for a coal plant it is \$2,743 per kW and (d) for wind it is \$2,134 per kW. To the best of
7 our knowledge, these costs do not include interest during construction or transmission
8 integration costs, although we cannot be completely certain as documentation for these
9 numbers is sometimes incomplete. Further, these estimates are in real terms rather than
10 nominal terms so we would expect them to be lower than our recommended ranges which
11 are in nominal terms.

12
13 Note also the wide range of the estimates across technologies. Public Service
14 Company of New Mexico, for example, provided an estimate for combined cycle which
15 is very close to the average, but it has relatively low coal costs. While we cannot say for
16 sure why this is, in our experience, in a rising cost market such as this, a utility's IRP
17 estimates can sometimes become "stale" if they do not have up-to-the-minute cost
18 numbers. This can lead to large jumps in estimates from one year to the next as updated
19 costs estimate are updated. For example Portland General Electric, in its 2007 IRP priced
20 a new coal plant at \$1,785 per kW and a new gas combined cycle plant at \$758 per kW.³⁵
21 As can be seen in the attached chart, they have revised those estimates one year later

³⁵ Portland General Electric, *Integrated Resource Plan 2009: Second Stakeholder Presentation & Discussion* (August 21, 2008) at slide 5.

1 numbers to \$2,900 per kW and \$1,300 per kW, respectively, for the coal- and the natural
2 gas-fired plants.

3
4 We should note, too, that the Minnesota Commission's decision is made more
5 difficult here because the Applicants are asking for approval of a project based upon cost
6 estimates rather than a price offer vetted through competitive solicitation or even a
7 detailed current price offer from an EPC contractor. In an IRP process which leads to a
8 competitive procurement, there is less risk to ratepayers if a resource planner
9 underestimates actual costs because the pass through of cost overruns is limited by a
10 fixed or fixed-formula price offer. Here, however, there is substantial risk to ratepayers
11 because Applicants are not promising to limit their cost recovery to their cost estimates.

12 13 **3. Conclusion**

14
15 Given this, we believe that the best practice for any analysis of resource choice
16 would be to account for this significant risk. The Applicants did not. The decision-
17 making process should, at a minimum, examine resource options with construction costs
18 at the "low" and "high" points of the ranges of costs per kW which we listed above: (a)
19 \$2,600 to \$3,000 per kW for coal; (b) \$1,000 to \$1,200 per kW for gas-fired combined
20 cycle, (c) \$800 to \$1,100 per kW for gas-fired combustion turbines; and (d) \$2,000 to
21 \$2,200 per kW for wind generation.

1 **C. Fuel Prices**

2

3 The third question we have been asked to address concerns the likely delivered

4 price of natural gas and coal for power plants in the region over the first fifteen years of

5 life for the power plants being evaluated. In this context, we were also asked to offer an

6 opinion on the potential impacts of proposed climate change legislation on fuel prices.

7 This is an important question because fuel costs are such a large portion of total plant

8 costs, particularly for natural gas-fired facilities.

9

10 Each Applicant has its own estimate of natural gas prices that are used for the

11 capacity expansion modeling, however, three of the five Applicants use prices that start

12 in the \$8 per MMBtu range around 2012 and escalate to the \$12/MMBtu range around

13 2026.³⁶ This is about a 3% increase per year. The one exception is MDU, which has

14 prices that start in the \$11/MMBtu range in 2012.³⁷ For coal, most Applicants use a coal

15 price of about \$1.80/MMBtu around 2012 escalating to around \$2.80/MMBtu in 2026.³⁸

16 The initial price translates into a delivered price for coal of about \$32 per ton in 2012.³⁹

17

18 In our opinion, the base fuel prices used by the Applicants are within a reasonable

19 range. However, the Applicants failed to analyze the resource choice at a wide range of

20 price projections for fuel prices. Because of the significant uncertainty surrounding gas

³⁶ Schumacher at p 6, Davis at Exhibit 117-F, Morlock at p 10-11. Heartland did not use capacity expansion modeling; instead, they compared Big Stone II against market purchases. See, Knofczynski at p 7 and 11.

³⁷ Heidell at p 16.

³⁸ Heidell at p 16, Schumacher at p 4, Davis at Exhibit 117-F.

³⁹ Assumes 8,800 btu/lb heat content.

1 prices it is necessary, in our opinion, to acknowledge the risk by analyzing the choice of
2 resources at a range of different price levels. Applicants' failure to adequately analyze
3 this risk means their analysis falls short of a best practice solution and could potentially
4 lead to the selection of a less robust resource.

6 **1. Futures Prices for Natural Gas**

8 Support for our conclusions that the base prices are reasonable, and also that risk
9 assessment is needed, comes from three sources. First, there are futures prices for natural
10 gas. One well-respected source of future prices is the New York Mercantile Exchange
11 (NYMEX). NYMEX is an important source of data because it includes futures contracts
12 for coal, oil, and natural gas. Looking at the prices for these contracts can give us some
13 idea of what the market expects prices to be in the near future. Indeed, by executing
14 NYMEX futures contracts today, a power plant owner can lock in the price she or he will
15 pay for natural gas in each month of each year for the next several years; a NYMEX
16 contract is a guarantee of that price.

18 NYMEX prices for natural gas futures have been declining since spiking over this
19 past summer. The average price for a year of natural gas futures spiked to roughly \$12
20 per MMBtu on fears of supply shortages. Average prices for one year of gas are now
21 around \$8 per MMBtu for the time period of June 2009 through May 2012. Figure One
22 (attached for pullout) shows this general trend by mapping average annual Henry Hub
23 futures prices for the NYMEX exchange on each trade date from January 2007 to the

1 present. That is, each line shows us, for a given trade date, the average price for one year
2 of futures contracts, from June to May.

3
4 As can be seen, the annual futures prices clustered around the \$8 per MMBtu line
5 on trade dates from January 2007 to January 2008. Then futures prices began to rise
6 reaching the \$12 per MMBtu mark in summer 2008. The futures prices then fall back to
7 about \$8 per MMBtu. We believe that some of this price drop is attributable to expanded
8 production from non-traditional gas supply sources. In particular, shale gas supply has
9 rapidly grown over the past few years and some predict that shale gas could eventually
10 supply almost half of the daily production in the U.S.⁴⁰ Those estimates are tempered by
11 the fact that there are questions concerning the cost of extracting shale gas given recent
12 downward price movements. Additionally, while LNG costs can be high because the
13 U.S. competes with other countries, the fact that the U.S. has sizable storage capacity can
14 also help to ease the price outlook; storage allows the U.S. to buy LNG when supply is
15 plentiful and prices are low.⁴¹

16
17 The point here is that the view of market participants, as reflected in prices for
18 NYMEX futures, supports the Applicants' use of a natural gas price in 2012 of \$8 per
19 MMBtu. However, the 2008 price spike shows there is volatility so a resource choice
20 must be assessed over a range of natural gas prices.

21

⁴⁰ Navigant Consulting, *North American Natural Gas Supply Assessment* (July 4, 2008) prepared for the American Clean Skies Foundation at p 11.

⁴¹ Federal Energy Regulatory Commission (FERC), *Staff Report: Gulf Coast Storms Exacerbate Tight Natural Gas Supplies; Already High Prices Driven Higher* (October 12, 2005) at p 3. FERC, *Winter 2005-2006 Energy Market Update Item No.: A-3* (March 16, 2006) at p 5 and 10.

2. Studies of Green House Gas Regulations

A second source of data that leads us to recommend the use of a range of fuel prices is the climate change studies referred to earlier in this report. While not all studies did so, several attempted to predict the effects of climate change legislation on fuel costs. Just as with CO₂ costs, the reports differ greatly on where gas prices would go in the future.

Driving the difference in numbers were many of the same forces which worked to create differing estimates of CO₂ allowance costs. For example, the more that renewable and nuclear technologies are used to generate electricity, in lieu of natural gas and coal technologies, the less price pressure will be on natural gas because there will be fewer electric generators buying natural gas to reduce CO₂ emissions. For example, in the EIA's Core scenario mentioned earlier, the natural gas price for utilities in 2020 was \$7.52 per MMBtu. In another case in which the development of nuclear power plants, carbon capture and sequestration (CCS) for coal plants, and renewable generation were restricted, the price moved to \$9.04/MMBtu, or about 20% higher than the core scenario.⁴² Liberal offset and banking provisions, which will help reduce allowance costs and keep coal use economical, will also serve to reduce future gas prices. The EIA analysis showed that when international offsets were not allowed, the gas price in the case with restricted nuclear, renewables and CCS growth moves up even more to \$11.68/MMBtu in 2020, or 55% above the core scenario.⁴³

⁴² EIA April 2008 at Table ES2.

⁴³ Ibid.

3. IRP Fuel Price Forecasts

The final source of data that supports both the \$8 per MMBtu forecast, as well as the need to use a range of forecasts, is utility price predictions. Again, IRPs reveal how different utilities go about planning in the face of significant uncertainty. And, again, the general practice is to examine the resource choice at multiple fuel price levels. Table Four (attached for pullout) shows gas prices and price scenarios used in a selected group of IRPs. Table Four shows how utilities often test at least a “low” and a “high” case to assess resource choices in the face of gas price uncertainty. It must be noted that gas prices will vary by region for each utility. For example, utilities with access to relatively cheaper Rocky Mountain Basin gas will have a lower fuel cost than those with gas from, for example, the Sumas hub near Canada.

What is of interest to us is the range around that base forecast which is used for low and high natural gas price scenarios. The range in the five IRP forecasts shown, stated in percent above and below the base, are (a) plus 20% to minus 20%; (b) plus 43% to minus 29%, (c) plus 182% to minus 44%, (d) plus 32% to minus 27%, and (e) plus 45% to minus 12%. This variety gives us no clear guidance.

4. Coal Prices

1 While we focus on natural gas prices above, we should not ignore coal prices.
2 While Powder River Basin (PRB) coal has a reasonably steady price historically, there
3 could be price spikes and the cost of transportation could potentially increase. With
4 respect to commodity prices, NYMEX offers a “swap” contract that is based off of the
5 price of Powder River Basin coal at a certain date in the future. As of October 14th that
6 price was \$9.52 per ton for a November 2008 contract.⁴⁴ However, it is noteworthy that
7 future months are significantly higher. The price in 2011 was \$17.32 a ton.⁴⁵ With
8 respect to transport, according to a statement made earlier this year, Ameren’s transport
9 rates, which had been about \$8 per ton, to take coal about 1,000 miles, went up to \$15 a
10 ton in 2006.⁴⁶

11
12 Significant here is that there is no futures market for transportation costs, which,
13 as noted, make up a significant portion of delivered coal costs. According to the EIA, the
14 transportation rate in 2001 for shipments to utilities in the West North Central Region
15 was \$8.24 a ton in 1996 dollars.⁴⁷ If we escalate that at 3% inflation to 2012 dollars, we
16 get a transportation rate of \$13.22/ton. Combining this with the current NYMEX swap
17 price of \$17.84 per ton (the current 2011 NYMEX price, plus one year of inflation at 3%)
18 we get a total delivered price in 2012 of \$31.06/ton, which translates to an energy price of
19 about \$1.76/MMBtu, about what the Applicants are using.⁴⁸

20

⁴⁴ Nymex.com at http://www.nymex.com/QP_spec.aspx.

⁴⁵ Ibid.

⁴⁶ St. Louis Business Journal, *Ameren eyes Illinois coal to combat transport costs* (March 28, 2008) at <http://stlouis.bizjournals.com/stlouis/stories/2008/03/31/story14.html>.

⁴⁷ Energy Information Administration, *Coal Transportation: Rates and Trends* (September 17, 2004) at Table 3.04.

⁴⁸ Heidell at p 16, Schumacher at p 4, Davis at Exhibit 117-F. Assumes 8,800 btu/lb heat content.

5. Conclusion

In conclusion, the Applicants' fuel prices appear to be acceptable for a "base case" analysis. However, the fact that there was no assessment of the resource choice at a wide range of fuel price levels means that the analysis did not adequately assess the risk of fuel price changes. We would suggest that the Applicants should have, at a minimum, analyzed a "low" and "high" natural gas price.

We are open on the method used to establish the range. One approach would be to allow historical price volatility to dictate the range. Table Five (attached for pullout) displays average monthly futures prices for four fiscal years: (a) June 2008 to May 2009; (b) June 2009 to May 2010; (c) June 2010 to May 2011; and (d) June 2011 to May 2012. We will note that for all these four years, the expectation is that the average price will be about \$8 per MMBtu which, again, matches the Applicants' base price forecast.

Table Five shows one measure of how futures prices varied around that annual average. The measure of variation is to state the futures price at the 95th and 5th percentile. These two fuel prices give us a high and low set of average annual futures prices actually seen in the futures market. So Table Five shows that these historical price data (a) reveal an average annual futures price of \$7.97 per MMBtu, (b) an average high price of \$10.06 per MMBtu or 26% higher than the average; and (c) an average low price of \$5.95 per MMBtu or 25% below the average. Based on these historical data, we

- 1 suggest that a range of plus and minus 25% be used around the \$8 per MMBtu natural
- 2 gas price forecast.
- 3 This concludes our report.

TABLES

TABLE ONE
COST OF A CO₂ ALLOWANCE UNDER LIEBERMAN-WARNER BILL (S. 2191)

Study	Year's Dollar	Dollars Per ton of CO2			
		2015	2020	2025	2030
EPA - Base Case S 2191-ADAGE Model ¹	2005	\$29	\$37	\$48	\$61
EPA - Base Case S 2191-IGEM Model ²	2005	\$40	\$51	\$65	\$83
MIT - 15% Offsets and CCS Subsidy ³	2005	\$48	\$58	\$71	\$86
EIA Core Case ⁴	2006	\$21	\$30	\$43	\$61
CBO ⁵	Nominal	\$35	N/A	N/A	N/A
CRA International - With Banking Case ⁶	2005	\$48	\$58	N/A	\$84
Clean Air Task Force ⁷	2005	N/A	\$21	\$31	\$46

1. Environmental Protection Agency, *EPA Analysis of the Lieberman-Warner Climate Securities Act of 2008* (March 14, 2008). Applied Dynamic Analysis of the Global Economy (ADAGE) Model. s2191 Scenario at p 27.
2. Environmental Protection Agency, *EPA Analysis of the Lieberman-Warner Climate Securities Act of 2008* (March 14, 2008). Intertemporal General Equilibrium Model (IGEM). S2191 Scenario at p 27.
3. Paltsev et al., *Assessment of U.S. Cap-and-Trade Proposals*, MIT Joint Program on the Science and Policy of Global Change (April 2007) at Appendix D, p 21.
4. Energy Information Administration (EIA), *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007* (April 2008), Core Case.
5. Congressional Budget Office (CBO), *S. 2191 America's Climate Security Act of 2007* (April 10, 2008) at p 8, Table 2.
6. Charles River Associates (CRA) International Modeling data on S.2191 reported in *Insights from Modeling Analyses of the Lieberman-Warner Climate Security Act* by Pew Center on Global Climate Change (May 2008) at p 14-15.
7. Clean Air Task Force, *America's Climate Security Act of 2007 - Modeling Results from the National Energy Modeling System* (February 2008) Raw Data Download: (http://www.catf.us/publications/presentations/CATF_S2191_with_CAFE.xls)

TABLE TWO
EMISSIONS COSTS USED IN RESOURCE PLANS

Company	Levels Used in Modeling (\$/ton)	Start Year for costs
Avista ¹	\$23.46	2012
Xcel Energy - Northern States Power Company ²	\$9, \$20, \$40	2010
Xcel Energy - Public Service Company of Colorado ³	\$10, \$20, \$40	2010
Public Service Commission of Wisconsin ⁴	\$0, \$22.66 (2006\$)	N/A
Puget Sound Energy ⁵	\$27, \$37, \$55 ⁶	2012
Public Service Company of New Mexico ⁷	\$8, \$20, \$40, \$53	2010
Portland General Electric ⁸	\$0, \$7.72 (2010\$), \$10 (1990\$), \$25 (1990\$), \$40 (1990\$)	N/A
NorthWestern Energy ⁹	\$9.57, \$9.65	2010

1 Avista, Presentation entitled *Stochastic Analysis & Resource Portfolio Selection Modeling* presented by James Gall at the 2009 Integrated Resource Plan Technical Advisory Committee Meeting No. 2 (August 27, 2008) at slide 6. Number is expected value of results from stochastic modeling that considers a range of costs from \$8.70 to \$80.80.

2 Northern States Power Company, *2007 Minnesota Resource Plan* (December 14, 2007) at Chapter 4, p 4-4.

3 Public Service Company of Colorado, *2007 Colorado Resource Plan* (November 15, 2007) at Volume 1 - Sections 1.6 through 1.12 at p 1-57 and 1-68.

4 Public Service Commission of Wisconsin, *Strategic Energy Assessment Draft Report: Energy 2014* (September 2008) at p 20.

5 Puget Sound Energy, Presentation entitled *Draft Aurora Price Forecasts* presented by Villamor Gamponia at the 2009 IRP Advisory Group Meeting (August 19, 2008) at slide 6.

6 Note an additional "Backslide" scenario not listed in the table above states, "250 MW or greater \$1.60/ton for 20% of total CO2" (Draft Aurora Price Forecasts at slide 6.)

7 Public Service Company of New Mexico, *Electric Integrated Resource Plan for the Period 2008-2027* (September 16, 2008) at p 99.

8 Portland General Electric, *2007 Integrated Resource Plan* (June 29, 2007) at p 198-200.

9 NorthWestern Energy, *2007 Electric Default Supply Resource Procurement Plan* (December 17, 2007) at p 47-49. A third case was also modeled. In this case it started at \$9.57 only in 2016.

TABLE THREE
CONSTRUCTION COST ESTIMATES FROM RECENT PLANNING PROCESSES

Company	Year's Dollar	Capital Costs (\$/kW)			
		CCCT	SCCT ⁹	Coal	Wind
Avista ¹	2009	\$900	\$900	\$3,000	\$2,400
Xcel Energy - Public Service Company of Colorado ²	2007	\$766	\$1,085	N/A	\$1,645
Public Service Commission of Wisconsin ³	2006	\$875	\$695	\$2,965	\$2,070
Puget Sound Energy ⁴	2008	\$1,257	\$1,199	\$2,878	\$2,433
Public Service Company of New Mexico ⁵	Dec. 2007	\$1,002	\$963	\$2,065	\$1,933
Portland General Electric ⁶	2008	\$1,300	\$1,200	\$2,900	\$2,500
NorthWestern Energy ⁷	2007	\$894	\$756	\$2,395	\$1,960
Idaho Power Company ⁸	2007	\$1,071	N/A	\$3,000	N/A
Simple Average		\$1,008	\$971	\$2,743	\$2,134

1 Avista, Presentation entitled *2009 IRP Resource Assumptions* presented by John Lyons at the 2009 Integrated Resource Plan Technical Advisory Committee Meeting No. 2 (August 27, 2008) at slide 9.

2 Public Service Company of Colorado, *2007 Colorado Resource Plan* (November 15, 2007) at Volume 1 Table 1.7-1 and Volume 2 Table 2.9-10.

3 Public Service Commission of Wisconsin, *Strategic Energy Assessment Draft Report: Energy 2014* (September 2008) at p 22, Table 6.

4 Puget Sound Energy, Presentation entitled *Draft Aurora Price Forecasts* presented by Villamor Gamponia at the 2009 IRP Advisory Group Meeting (August 19, 2008) at slide 18.

5 Public Service Company of New Mexico, *Electric Integrated Resource Plan for the Period 2008-2027* (September 16, 2008) at p 83-84, Figure 7-3.

6 Portland General Electric, *Integrated Resource Plan 2009: Second Stakeholder Presentation & Discussion* (August 21, 2008) at slide 5.

7 NorthWestern Energy, *2007 Electric Default Supply Resource Procurement Plan* (December 17, 2007) at p 85, Table 6-5.

8 Idaho Power Company, *2008 Integrated Resource Plan UPDATE* (June 2008) at p 24, Figure 6.

9 When the IRPs listed more than one option for SCCT we choose the more fuel efficient option.

TABLE FOUR
SAMPLE OF NATURAL GAS PRICE FORECASTS

Company	Base Case Gas Price (2012) per MMBtu	Other Gas Price (2012) Scenarios per MMBtu
Xcel Energy - Northern States Power Company ¹	\$7.90	Base Case +20% and -20%
Xcel Energy - Public Service Company of Colorado ²	\$7.00	Low: \$5, High: \$10
Public Service Company of New Mexico ³	\$8.25	\$4.65, \$11.63, \$12.62, \$17.44, \$23.25
NorthWestern Energy ⁴	\$7.71	Low: \$5.62, High: \$10.18
Idaho Power Company ⁵	\$6.33	\$5.57, \$6.04, \$9.18

1 Northern States Power Company, *2007 Minnesota Resource Plan* (December 14, 2007) at Chapter 7, Table 7-1.

2 Public Service Company of Colorado, *2007 Colorado Resource Plan* (November 15, 2007). Note, values are approximations. They are based on (a) Volume 1, Figures 1.7-1 and 1.8-6 and (b) Volume 1, p 1-67.

3 Public Service Company of New Mexico, *Electric Integrated Resource Plan for the Period 2008-2027* (September 16, 2008) at p 93, Figure 7-7.

4 NorthWestern Energy, *2007 Electric Default Supply Resource Procurement Plan* (December 17, 2007) at p 79, Table 6-2.

5 Idaho Power Company, *2008 Integrated Resource Plan UPDATE* (June 2008) at p 16, Table 6.

TABLE FIVE
AVERAGE OF MONTHLY NYMEX HENRY HUB FUTURES¹

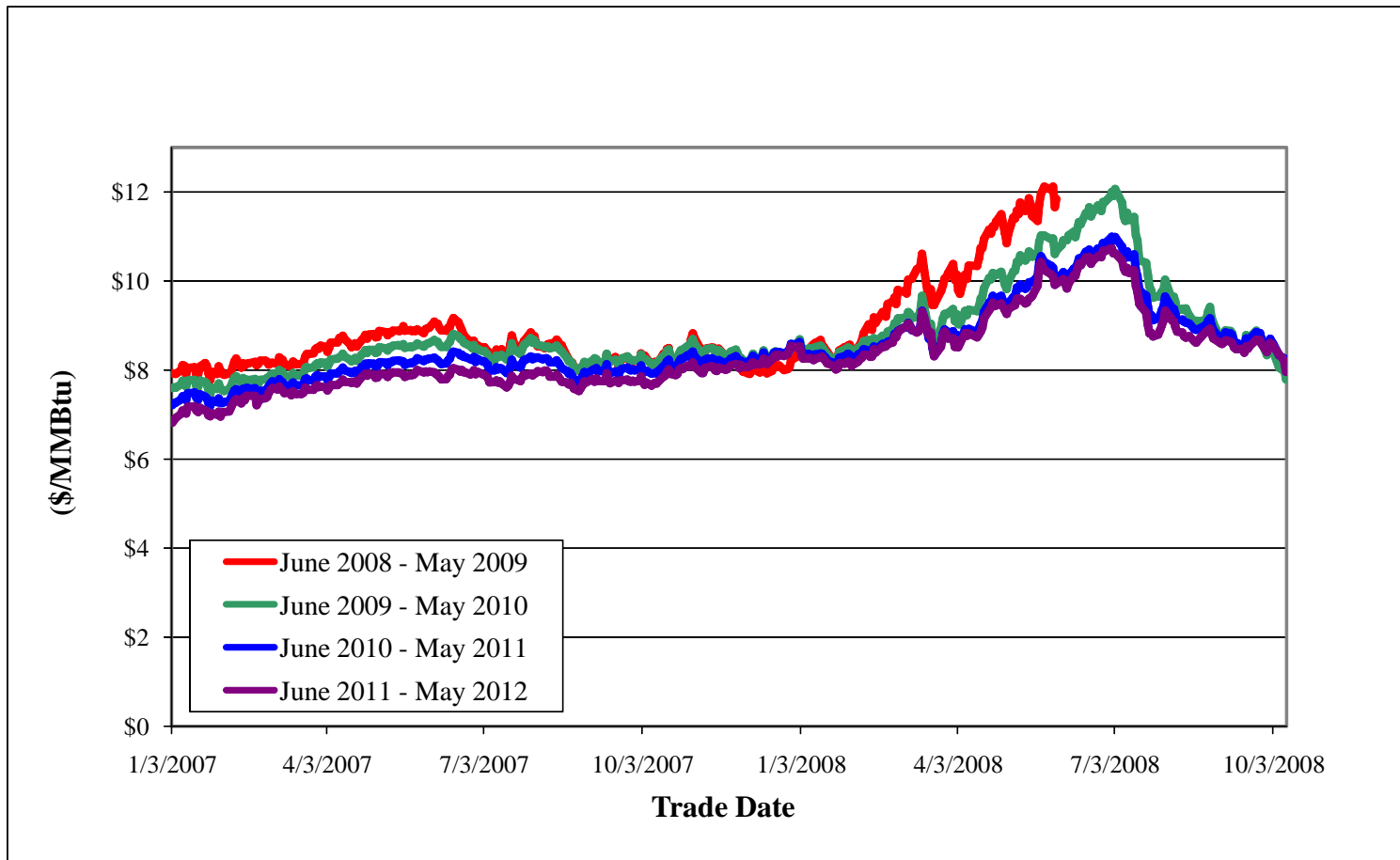
Contract Year ²	Average Price	Percentile	
		95th	5th
June 08 - May 09	\$8.27	\$10.07	\$5.97
June 09 - May 10	\$8.07	\$10.46	\$5.69
June 10 - May 11	\$7.69	\$9.83	\$5.32
June 11 - May 12	\$7.85	\$9.90	\$6.82
Simple Average:	\$7.97	\$10.06	\$5.95

1 New York Mercantile Exchange "NYMEX" Data as of October 10, 2008 (<http://www.nymex.com>).

2 Trade dates from January 3, 2005 through October 10, 2008 were used in the Table above.

FIGURES

FIGURE ONE
NYMEX FUTURES PRICE FOR NATURAL GAS AT HENRY HUB ¹



1. New York Mercantile Exchange "NYMEX" Data as of October 10, 2008 (<http://www.nymex.com>)

RESUMES AND LISTS OF TESTIMONY AND PUBLICATIONS

CRAIG R. ROACH

Craig Roach has over thirty-two years of experience working on investments in, policies for, and litigation concerning the electricity, natural gas, and other energy businesses. Craig founded and incorporated Boston Pacific in Washington, DC in 1987.

Craig leads the Boston Pacific Team which has served since 2004 as the External Market Advisor (EMA) for the Southwest Power Pool Regional Transmission Organization (SPP RTO). As the EMA, the Boston Pacific Team is responsible for developing the Market Monitoring Plan and Market Power Mitigation Measures for the SPP RTO which have won Federal Energy Regulatory Commission (FERC) approval. The EMA also plays a significant role in market design for SPP's new real-time market which successfully started operations on February 1, 2007.

Craig also oversees the Boston Pacific Teams which manage and monitor major power auctions such as those in Illinois, New Jersey, Maryland, Delaware, and the District of Columbia. Boston Pacific also manages and monitors unit contingent solicitations such as those in Oregon, Oklahoma, and the U.S. Virgin Islands.

Craig has extensive experience as an expert witness on the electricity and natural gas businesses. He has provided testimony, affidavits or comments on thirty occasions before FERC, to twenty-two State Commissions (some on multiple occasions) plus two Canadian Provincial Boards, and a City Council. He also has served as an expert in arbitrations, in Federal Court, in State Court, and before a Congressional Subcommittee.

The great variety of topics in Craig's testimonies documents the breadth and depth of his experience in the electricity and natural gas businesses. He has served as an expert witness on issues such as market power (antitrust), electric industry restructuring, competitive bidding, transmission tariffs, ratemaking by both electric and gas utilities, finance for both competitive power suppliers and utilities, system reliability, prudence of power purchases, contract abrogation, mergers and acquisitions, and resource choice. His expertise also is reflected in the fact that he is a widely sought-after speaker.

In previous years, Boston Pacific also had extensive, hands-on experience supplementing the in-house asset transaction teams of our clients for power project development and acquisition. We have done so throughout the U.S. and in two dozen countries around the world.

Prior to founding Boston Pacific, Craig was a Project Manager with ICF Incorporated. While at ICF, Craig developed an engineering-economic model to forecast industrial fuel choice, assessed the impact of air pollution regulations on coal markets, and identified opportunities for coal exports to Asia and Europe.

From 1975 to 1979, Craig was a Principal Analyst for the U.S. Congressional Budget Office. He provided analyses on energy and environmental legislation through written reports and testimony to Congressional committees.

Craig holds a Ph.D. in Economics from the University of Wisconsin. His major field was Public Finance and his minor field was Energy Engineering. Craig earned his B.S. in Economics, *cum laude*, from John Carroll University. Craig currently serves on the Advisory Board to University of Wisconsin's Department of Economics.

LIST OF TESTIMONY AND OTHER PUBLICATIONS FOR CRAIG R. ROACH, Ph.D.

TESTIMONY

Testimony concerning the design of the 2008 RFP, Oklahoma Corporation Commission Cause No. PUD 200700418 [June 2008]. Filed as the Oklahoma Commission's Independent Evaluator.

Comments concerning PacifiCorp's proposed acquisition of the Chehalis power plant, Oregon Public Utility Commission Docket No. UM 1374 [June 2008]. Filed as the Oregon Independent Evaluator.

Reply comments concerning the 2008 Procurement Process, before the Illinois Commerce Commission [May 2008]. Filed as the Procurement Monitor.

Comments concerning the 2008 Procurement Process, before the Illinois Commerce Commission [May 2008]. Filed as the Procurement Monitor.

Direct Testimony concerning the proposed acquisition of TXU by private equity investors, Public Utility Commission of Texas Docket No. 34077 [September 2007]. For the Texas Commission.

Comments concerning PacifiCorp's proposal to amend and delay its 2012 RFP, Oregon Public Utility Commission Docket No. UM 1208. [November 2007]. Filed as the Oregon Independent Evaluator.

Affidavit concerning allegations of above-market prices and price manipulation in the 2006 Illinois Auction, Federal Energy Regulatory Commission Docket No. EL07-47-000. [June 2007]. Filed as the Auction Monitor.

Support for settlement of an electric transmission rate case, Federal Energy Regulatory Commission Docket No. ER06-186-000. [March and April 2006]. For the City of Vernon.

Testimony concerning market power mitigation measures for the Southwest Power Pool energy imbalance services market, Federal Energy Regulatory Commission Docket No. ER06-451-000. [January 2006]. Filed as the Southwest Power Pool's Independent Market Monitor.

Comments on the Maryland procurement process for Standard Offer Service, Maryland Senate Special Commission on Electric Utility Deregulation Implementation. [August 2005]. Appearing as the Technical Consultant for the Maryland Public Service Commission.

Direct and Supplemental Testimony concerning market power mitigation measures for the Southwest Power Pool energy imbalance services market, Federal Energy Regulatory Commission Docket No. ER05-1118-000. [June and August 2005]. Filed as the Southwest Power Pool's Independent Market Monitor.

Comments on the open access status of a transmission line, Federal Energy Regulatory Commission Docket No. ER05-1072-000. [June 2005]. Filed as the Southwest Power Pool's Independent Market Monitor.

Direct Testimony regarding the benefit of continuing PUCT Capacity Auctions in Texas, Public Utility Commission of Texas, Docket No. 30882. [May 2005]. For Reliant Energy, Inc.

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FRANK MOSSBURG

Frank has detailed experience in the design and monitoring of successful procurements of all types. He serves as the lead contact for several unit-contingent RFPs from PacifiCorp for the Oregon Commission, including the 2012 Baseload, 2008 All Source and 2008R-1 Renewables RFP. He also served as a lead writer for Boston Pacific's analysis of PacifiCorp's request for competitive bidding waiver to purchase the Chehalis plant. In these projects he has helped in all stages of the procurement, from analyzing and advising on the RFP design, to evaluating bids, to observing contract negotiations. He has appeared before the Commission on multiple occasions to provide recommendations regarding RFP design.

Frank is also the lead contact for the SOS procurements in the District of Columbia and Delaware, and the BGS Auction in New Jersey. For these engagements, he interacts with utilities, Commission Staff and bidders to design successful processes and assess the competitiveness of bids. He is also responsible for developing the technical analyses that we employ on these engagements, such as our benchmark models, and for leading analyses of utility-produced models and data. He has appeared formally and informally before Commissioners and Staff to explain how procurement results came to be.

In his initial tenure at Boston Pacific, prior to earning his MBA, Frank specialized in creating complicated valuation models from extremely large sets of data then summarizing his findings in clear and concise language. He worked with clients and law firms to develop and defend detailed analyses that could withstand the rigors of contentious litigation.

Frank has used massive databases to value assets on multiple occasions, creating new and unique models that account for each asset's special considerations. In one instance he worked with developers and experts to simulate alternate dispatch and contract scenarios to value the benefit of new power plant development. In another instance he collaborated with clients to value proposed "reverse tolling" agreements.

Frank's work also has extended to regulatory testing and studies. He designed the HHI analysis for Reliant Resources acquisition of Orion power. He has also conducted Hub-and-Spoke and Supply Margin Analysis tests which allowed major power producers the right to sell at market rates. He helped author Boston Pacific's report on market price volatility *Still Waters Run Deep*.

Frank has worked at IBM in their Business Consulting Services division. While there he helped manage the updating of a Navy cost database system while conducting process improvement actions to ensure a better and faster flow of information to military cost estimators. He also worked with personnel to answer questions and create custom data queries. Frank also had the opportunity to work at a boutique investment banking division which specialized in mergers and acquisitions in the electric and gas space.

Frank has also been a Director at Analysis Research Planning Corporation (ARPC). There he engaged in a variety of sophisticated analytical projects. In one instance he combined extensive historical data with a Monte Carlo simulation to forecast defense costs for a major pharmaceuticals manufacturer. He designed claims valuation models for Asbestos and Silica claimants using complicated regressions and coefficient balancing formulas to generate fair outcomes for thousands of claimants.

Frank graduated *cum laude* from the Wharton Undergraduate School of the University of Pennsylvania with a BS in Economics and a concentration in Finance. He received his MBA from the University of Virginia's Darden Graduate School of Business Administration.