
**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA**

In the Matter of the Application by Otter Tail Power Corporation, d/b/a Otter Tail Power Company for an Advance Determination of Prudence for the Big Stone II Generating Plant) **Case No. PU-06-481**
And) **and**
In the Matter of the Application of Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. for an Advance Determination of Prudence of Montana-Dakota's Participation & Ownership Interest in the Big Stone II Generating Station) **Case No. PU-06-482**

**Supplemental Direct Testimony of
David A. Schlissel
Synapse Energy Economics, Inc.**

**On Behalf of
Mark Trechock
and
Dakota Resource Council**

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APRIL 9, 2008

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List of Exhibits

- Exhibit DAS-S1: Current resume of David A. Schlissel.
- Exhibit DAS-S2: *Increasing Construction Costs Could Hamper U.S. Utilities' Plans to Build New Power Generation*, Standard & Poor's Rating Services, June 2007.
- Exhibit DAS-S3: *Rising Utility Construction Costs: Sources and Impacts*, the Brattle Group, September 2007.
- Exhibit DAS-S4: *Top 10 U.S. Electric Utility Credit Issues for 2008 and Beyond*, Standard & Poor's Rating Services, January 2008.
- Exhibit DAS-S5: *Carbon Principles*, adopted by Citigroup, JP Morgan Chase, and Morgan Stanley, February 2008.
- Exhibit DAS-S6: Confidential Documents Cited in this Supplemental Testimony.

1 **1. Introduction**

2 **Q. What is your name, position and business address?**

3 A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy
4 Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

5 **Q. On whose behalf are you testifying in this case?**

6 A. I am testifying on behalf of Mark Trechock and Dakota Resource Center
7 (“DRC”).

8 **Q. Have you testified previously in this Proceeding?**

9 A. Yes. I filed direct testimony in this proceeding on May 31, 2007.

10 **Q. Have you included a current copy of your resume as an exhibit?**

11 A. Yes. A current copy of my resume is included as Exhibit DAS-S1.

12 **Q. What is the purpose of your supplemental testimony?**

13 A. Synapse was retained by the DRC to evaluate the supplemental testimony and
14 analyses filed by Otter Tail Power Company (“OTP”) and Montana-Dakota
15 Utilities (“MDU”) in Minnesota in mid-November 2007 and here in North Dakota
16 on March 10, 2008. The filing of these new pieces of testimony and analyses
17 followed the withdrawal of GRE and SMMPA from the Big Stone II Project. This
18 testimony presents the results of our assessments of the new testimony and
19 analyses presented by OTP and MDU.

20 **Q. Were there other members of the Synapse staff who also assisted in the**
21 **analyses undertaken by Synapse as part of its evaluation of the Supplemental**
22 **Testimony and analyses submitted by OTP and MDU?**

23 A. Yes. Dr. David White, Bruce Biewald, Michael Drunsic, Richard Hornby, Robin
24 Maslowski, and Robert Fagan also were members of the Synapse team who have
25 evaluated the new Big Stone II related testimony, exhibits and analyses that have
26 been prepared by or for the Project Owners (including OTP and MDU) since last

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1 October. Former Synapse staff member Anna Sommer also assisted in this
2 review. Copies of their resumes are available at www.synapse-energy.com.

3 **Q. Please summarize your conclusions.**

4 **A. My conclusions are as follows:**

- 5 1. Increasing numbers of proposed coal-fired power plants have been
6 cancelled, delayed and rejected by state regulatory commissions or boards
7 within the past year because of, or at least in large part due to, the
8 uncertainties and risks regarding future power plant construction costs and
9 the potential for regulation of power plant CO₂ emissions.
- 10 2. Developments in the nearly ten months since I last filed testimony in this
11 proceeding confirm the conclusion in my May 31, 2007 testimony that the
12 potential for further increases in construction costs and the potential for
13 future federal restrictions on CO₂ emissions are very significant
14 uncertainties and risks for the Big Stone II Project. However, OTP and
15 MDU have not adequately considered these uncertainties and risks in the
16 new testimony and analyses that they have submitted to the Commission.
- 17 3. Soaring power plant construction costs will have a significant impact on
18 the results of properly performed resource planning. Actual and recently
19 estimated power plant capital costs have been strongly affected by the
20 domestic and international competition for design and construction
21 resources, manufacturing capacity and commodities. It would be
22 imprudent to not allow for the possibility that these same factors which
23 have led to the skyrocketing of power plant construction costs in recent
24 years will continue to significantly affect project costs during the design
25 and construction of the proposed Big Stone II Project. However, OTP has
26 prepared only a single economic modeling scenario that considered only a
27 10 percent further increase in the cost of building the Big Stone II Project.

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1 MDU has not prepared any economic modeling analyses that consider any
2 additional increases in the cost of the Big Stone II Project.

3 4. Events in the past year also demonstrate that it is even more certain that
4 the federal government at some point in the near future will regulate CO₂
5 emissions from power plants. Federal regulation is coming and it is
6 reasonable to expect that it will have a very substantial impact on the cost
7 of operating a coal-fired power plant like the proposed Big Stone II
8 Project. It cannot be prudent for OTP and MDU to continue their
9 participation in the Project without fully considering the risk of significant
10 CO₂ prices in their resource planning process.

11 The Big Stone II Applicants, including OTP and MDU, have not prepared a new
12 construction cost estimate for the Big Stone II Project since July of 2008, almost
13 two years ago. Yet both companies are asking the Commission for a blank check
14 to proceed with their participation in the Big Stone II Project. My
15 recommendation remains the same today as it was back in May 2007: the
16 Commission should reject OTP and Montana-Dakota's request for an Advance
17 Determination of Prudence for their participation in the Big Stone II Project. If
18 the Commission does grant an Advanced Determination of Prudence, it should be
19 limited to the current cost estimate for the Big Stone II Project.

20 **Q. Please explain how you conducted your new investigations of OTP and MDU**
21 **supplemental testimony and analyses in this proceeding.**

22 A. We have reviewed all of the testimony and exhibits filed by OTP and MDU in
23 this proceeding and by the Big Stone II Applicants in Minnesota Public Utilities
24 Commission Dockets Nos. CN-05-619 and TR-05-1275 ("the Minnesota PUC
25 CON Dockets").

26 In addition, we have participated in discovery in this proceeding and the
27 Minnesota PUC CON Dockets. As part of that work, we have prepared
28 information requests that were submitted to OTP, MDU, and the other remaining

1 Big Stone II Applicants and have reviewed the responses to those information
2 requests and to the discovery submitted by other parties including the
3 Commission Staff in this proceeding and the Department of Commerce in
4 Minnesota.

5 Finally, last fall we reran the Strategist model for MDU.

6 **2. Regional Capacity Needs**

7 **Q. Do you have any comments about Applicant witness Uggerud’s discussion of**
8 **regional capacity needs?**¹

9 A. Yes. I have a number of comments about Mr. Uggerud’s discussion of regional
10 capacity needs.

11 First, I agree that serious actions need to be taken by the load serving entities,
12 generators, state governments and the Midwest Reliability Organization (“MRO”)
13 to address possible capacity deficits. However, those actions need to be
14 consistent with regional and state efforts to reduce CO₂ emissions and to increase
15 the region’s dependence on renewable resources. Building the Big Stone II
16 Project, which would emit approximately 3.8 to 4.3 million tons of CO₂ each
17 year, would be a major step in the wrong direction at this time. The Commission
18 should not be panicked into granting an Advanced Determination of Prudence for
19 an uneconomic coal-fired power plant by the threat of a “looming generation
20 capacity deficits” as suggested by Mr. Uggerud.²

21 Instead, the Commission should require that OTP and MDU adopt policies and
22 alternatives that provide needed energy at the lowest cost, subject to
23 considerations of risk. As I will explain, OTP and MDU have not shown that
24 building a new multi-billion dollar coal plant is a less expensive and lower risk
25 option than expanding efforts on renewable resources and energy efficiency and,

¹ OTP Exhibit 112, at pages 2-4.

² Id., at page 3, lines 5-8.

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1 where necessary, adding some efficient new gas-fired combined cycle and
2 peaking capacity. This is especially true given the significant cost uncertainties
3 surrounding regulation of greenhouse gas emissions and the ultimate cost and
4 completion date of the Big Stone II Project.

5 Second, the North American Electric Reliability Corporation (“NERC”)
6 assessment cited by Mr. Uggerud only shows that additional capacity is needed
7 during the peak summer hours. It does not show whether that additional capacity
8 should be peaking capacity, intermediate capacity or baseload capacity. The
9 flawed and biased new modeling analyses presented by OTP and MDU are the
10 only evidence that has been presented to show that adding new baseload
11 generating capacity is the most economic option.

12 Third, there is no evidence that the capacity and load information in the NERC
13 Long-Term Assessment relied upon by Mr. Uggerud reflects any of the many
14 changes that are occurring in the region regarding energy usage and the types of
15 capacity that will be needed. These changes include the new Minnesota statute
16 establishing a statewide goal of achieving annual savings of 1.5 percent of retail
17 energy sales of electricity and natural gas,³ the new Minnesota Renewable Energy
18 Objective Statute,⁴ efforts in other states to reduce energy and capacity demands
19 and to increase the amounts of electricity generated from renewable energy
20 resources, actions at the federal level such as the recent adoption of new appliance
21 standards as part of the new energy bill, developments in the MISO energy
22 markets, and the development by MISO of rules allowing the participation of
23 demand response resources in the ancillary services markets.

24 For example, when it announced its withdrawal from the Big Stone II Project in
25 September 2007, Great River Energy cited the following as one of the reasons for
26 its decision to leave the Project:

³ Minn. Stat. Sec. 216B.241 subd. 1c and Minn. Stat. Sec. 216B.2401.

⁴ Minn. Stat. Sec. 216B.1691.

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1 The cost of Big Stone II has increased due to inflation and project
2 delays. Although the costs of alternative resources have also
3 increased, Great River Energy now anticipates the energy markets
4 through the Midwest Independent System Operator (MISO), will
5 provide access to additional lower-cost alternatives than initially
6 assumed.⁵

7 Another significant new development is the agreement by nine states in the
8 region, working together through the Midwest Governors Association, to adopt
9 the goal of meeting at least 2 percent of regional annual retail sales of electricity
10 through energy efficiency improvements by 2015, with additional savings in
11 subsequent years, and adopted regional renewable energy goals of 10% by 2015,
12 20% by 2020, 25% by 2025, and 30% by 2030.⁶ All of these changes will affect
13 how much new capacity will be needed and what capacity will be the most
14 economic to add, as well as the potential for ratepayer benefits from off-system
15 sales as coal generated power becomes more expensive in the market.

16 Fourth, as Xcel Energy has explained in its recently filed 2007 Resource Plan,
17 analyses are currently underway that may result in reduced regional reserve
18 requirements:

19 We currently plan to obtain sufficient capacity to meet all of our
20 projected needs plus a 15% MAPP reserve margin. In the past
21 year, there has been much discussion and change among Midwest
22 utilities with respect to reserve margins . . . MRO is in the process
23 of developing new resource adequacy standards for our region that
24 will likely go into effect toward the end of 2008. . . early
25 indications are that the reserve margin resulting from this [LOLE]
26 study will be lower than the 15% reserve margin currently
27 required. However, the MDC ratings of units are also lower than
28 our URGE ratings . . . we expect an overall reduction in our
29 planning reserve requirement but do not yet have enough
30 information to calculate an estimate. In order to evaluate the
31 impact of changing reserve margins on our future resource

⁵ Great River Energy September 17, 2007 press release available at:
http://www.greatriverenergy.com/press/news/091707_big_stone_ii.html

⁶ Midwest Governors Association, "Energy Security and Climate Stewardship Platform for the Midwest, 2007," Nov. 15, 2007. The Platform was agreed to by Indiana, Illinois, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota, Wisconsin and the province of Manitoba.

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1 requirements, we evaluated our Resource Plan using reserve
2 margins of 12% and 15% based on our median (50/50) peak
3 forecast and our unit MDCs.⁷

4 **Q. Is it possible that adding new baseload generating capacity could be the more**
5 **economic option even if the capacity is not needed for system reliability or if**
6 **there is only a need for peaking capacity?**

7 A. Yes. It is possible that the addition of a new baseload generating facility can be
8 the lowest cost option even if all of the capacity from that facility is not
9 immediately needed to ensure that an adequate level of system reliability.
10 However, as I will explain later in this testimony, the new modeling analyses
11 presented by OTP and MDU are flawed and biased in favor of the Big Stone II
12 Project and, therefore, do not represent credible evidence that the Project is the
13 lowest cost option available to OTP and MDU.

14 **Q. Is it even certain that the Big Stone II Project will be in service by 2013?**

15 A. No. Completion of the Project in 2013 is not guaranteed. The recent experience
16 of numerous other coal-fired power plant construction projects suggests that the
17 completion of the Big Stone II Project will occur later and cost far more than OTP
18 and MDU now admit.

19 **Q. Mr. Uggerud expresses concern about relying “solely on natural gas,**
20 **conservation or renewable energy instead” and “over-reliance on natural**
21 **gas.”⁸ Are you recommending that OTP and MDU rely “solely” on natural**
22 **gas, conservation or renewable energy?**

23 A. No. I am recommending that OTP and MDU investigate and implement portfolios
24 of alternatives to the Big Stone II Project that would include energy efficiency,
25 more renewable resources, and, to the most limited extent necessary, the addition
26 of new natural gas-fired capacity. In fact, regardless of what happens with the

⁷ Northern States Power Company, *2007 Resource Plan*, Docket No. E002/RP-07___, December 14, 2007, at pages 4-4 and 4-5.

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1 Big Stone II Project, OTP and MDU still will maintain their existing coal-fired
2 facilities. So we are not recommending that any of them rely “solely” on natural
3 gas, conservation or renewable energy.

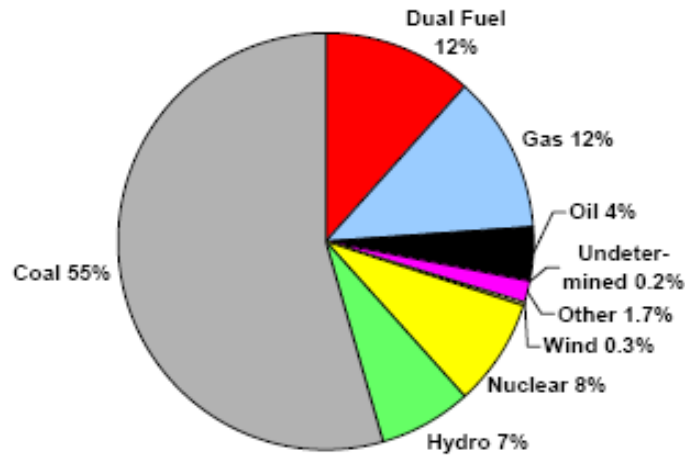
4 **Q. Do you agree with Mr. Uggerud that over-reliance on natural gas is a**
5 **concern?**

6 A. In general, I do agree that over-reliance on natural gas can be a concern.
7 However, in this specific instance and in this specific area of the nation, it does
8 not appear that the MRO would be overly reliant on natural gas if the Commission
9 rejected OTP and MDU request to build the Big Stone II Project.

10 Figures 1 and 2 below are taken from the same NERC *2007 Long-Term*
11 *Assessment Reliability Assessment 2007-2016* that Mr. Uggerud references in his
12 Supplemental Direct Testimony. These Figures show that in 2006, the region’s
13 generating capacity was 55 percent coal-fired and only 12 percent gas-fired (24
14 percent if gas-fired capacity and dual fuel capacity are considered together). It
15 further shows that in 2012, the region’s generating capacity will still be 55 percent
16 coal-fired and only 13 percent gas-fired (still 24 percent if gas-fired and dual fuel
17 are considered). The replacement of the Big Stone II Project, in part, by natural
18 gas-fired capacity will not significantly change these figures. Thus, there is no
19 real danger of over-reliance on natural gas in the upper Midwest. There could be
20 a concern in other regions of the nation but not in the upper Midwest.

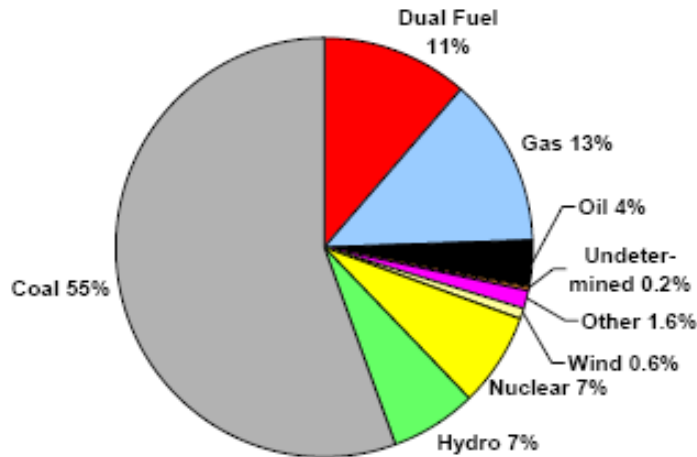
⁸ OTP Exhibit 112, at page 16, lines 16-17.

1 **Figure 1: MRO Capacity Fuel Mix 2006**



2

3 **Figure 2: MRO Capacity Fuel Mix 2012**



4

5 Instead of worrying about having OTP and MDU increase their dependence on
6 natural gas-fired generation, the Commission should be concerned about these
7 companies increasing their dependence on coal-fired generation. For example,
8 MDU witness Stomberg has testified that with Big Stone II, MDU would increase
9 its dependence on coal-fired generation from 77 percent of its installed capacity
10 resources to 82 percent.⁹ This is an extremely risky plan given the near certainty

⁹ MDU Exhibit 213, at page 7, lines 13-17.

1 of federal regulation of CO₂ emissions, costs trends for coal and rail service from
2 the Powder River Basin.

3 **3. OTP and MDU Have Not Adequately Considered The Risks**
4 **Associated With Building A New Coal-Fired Generating Unit**

5 **Q. Last year you testified that OTP and MDU had failed to adequately consider**
6 **the risks associated with evaluating the economics of participating in the**
7 **proposed Big Stone II Project. Is that still your conclusion after reviewing**
8 **the supplemental testimony and analyses submitted by OTP and MDU on**
9 **March 10, 2008?**

10 A. Yes.

11 **Q. You testified in your May 31, 2007 Direct Testimony that the potential for**
12 **future restrictions on CO₂ emissions and the potential for large increases in**
13 **the project's capital cost were significant uncertainties and risks facing the**
14 **Big Stone II Project. Do these remain significant uncertainties and risks for**
15 **the Project?**

16 A. Yes. Developments over the past nearly ten months since I submitted my May
17 31, 2007 testimony in this proceeding confirm and re-emphasize that the potential
18 for future restrictions on CO₂ emissions and the potential for large increases in
19 capital costs are very significant uncertainties and risks associated with building
20 and operating new coal-fired generating plants like the proposed the Big Stone II
21 Project.

22 I also want to note that there also are other potential uncertainties and risks for
23 new coal plants. These other uncertainties and risks include the potential for
24 higher fuel prices, fuel supply disruptions that could affect plant operating
25 performance; the potential for increasing stringency of regulations of current
26 criteria pollutants; and the potential for expanded state and/or federal energy
27 efficiency and renewable energy requirements.

1 **Q. What consideration have OTP and MDU given in their supplemental**
2 **testimony to the risks associated future project capital cost increases and the**
3 **potential for restrictions on future CO₂ emissions?**

4 A. OTP has only given very limited consideration to the potential for future increases
5 in the cost of building the Big Stone II Project. MDU has not given any
6 consideration in its economic modeling analyses to the potential that the cost of
7 building Big Stone II will increase further. Neither company has given any
8 consideration in their modeling analyses in this proceeding to the risks associated
9 with future CO₂ emissions.

10 **Q. Is this a reasonable approach?**

11 A. No. Higher CO₂ prices and increased Project construction costs or additional
12 schedule delays, on their own or in combination, will impact the Project's
13 economics relative to other alternatives and may make the proposed Big Stone II
14 Project uneconomic for of OTP and/or MDU. The important reason to prepare
15 sensitivities is to determine what changes in construction costs and/or CO₂ prices
16 would make the Project uneconomic and then to evaluate how likely those
17 changes are. Unfortunately, OTP and MDU did not prepare these critical analyses.
18 This is imprudent. Risk and uncertainty are inherent in all enterprises. They do
19 not go away merely because they are ignored in economic analyses.

20 **Q. Have other companies provided sensitivity analyses for key input parameters**
21 **in their Integrated Resource Plans or in the modeling analyses presented in**
22 **support of requests to build and operate new generating facilities?**

23 A. Yes. We have seen such sensitivity analyses for key input parameters in many of
24 the power plant cases in which we have been involved in recent years.

1 **Q. Have you seen any recent instances in which companies have decided not to**
2 **undertake new coal-fired power plants because of concerns over increasing**
3 **construction costs and/or the potential for federal regulation of greenhouse**
4 **gas emissions?**

5 A, Yes. In just the past few months, a number of companies have announced that
6 they will not pursue new coal-fired generating facilities. For example, in its
7 Resource Plan filed in Colorado in November 2007, Xcel Energy concluded that:

8 In sum, in light of the now likely regulation of CO₂ emissions in
9 the future due to a broader interest in climate change issues, the
10 increased costs of constructing new coal facilities, and the
11 increased risk of timely permitting to meet planned in-service
12 dates, Public Service does not believe it would be prudent to
13 consider at this time any proposals for new coal plants that do not
14 include CO₂ capture and sequestration.¹⁰

15 In its 2007 Resource Plan in Minnesota, Xcel Energy similarly noted that “given
16 the likelihood of future carbon regulation, we have only modeled a future coal-
17 based resource option that includes carbon capture and storage.”¹¹ Xcel Energy
18 also noted in its 2007 Minnesota Resource Plan that “Adding coal resources
19 without sequestration would significantly add carbon and risk for our
20 ratepayers.”¹²

21 Minnesota Power Company also has announced that it is considering only carbon
22 minimizing resources and would not consider a new coal resource without a
23 carbon solution.¹³ The Company also said that in the long-term it would consider

¹⁰ Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-34.

¹¹ Northern States Power Company, *2007 Resource Plan*, Docket No. E002/RP-07___, December 14, 2007, at page 4-1.

¹² *Id.*, at page 11-9.

¹³ *Petition for Approval, Minnesota Power’s 2008 Resource Plan*, Minnesota Public Utilities Commission Docket No. E015/RP-07-1357, dated October 31, 2007, at page 5.

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1 pulverized coal and IGCC plants but only with proven carbon capture and CO₂
2 sequestration technologies.¹⁴

3 Idaho Power Company similarly has concluded that:

4 Due to escalating construction costs, the transmission cost
5 associated with a remotely located resource, potential permitting
6 issues, and continued uncertainty surrounding GHG laws and
7 regulations, IPC [Idaho Power Company] has determined that coal-
8 fired generation is not the best technology to meet its resource
9 needs in 2013. IPC has shifted its focus to the development of a
10 natural gas-fired combined cycle combustion turbine located closer
11 to its load center in southern Idaho.¹⁵

12 Avista Utilities, in Idaho, also has announced that it will not pursue coal-fired
13 power plants in the foreseeable future.

14 **Q. Have any proposed coal-fired generating projects been cancelled or delayed**
15 **as a result of concern over increasing construction costs or the potential for**
16 **federal regulation of greenhouse gas emissions?**

17 A. Yes. According to published reports, more than 20 coal-fired power plant
18 projects have been cancelled or rejected by state regulatory commissions or
19 boards since December 2006 and more than three dozen others have been
20 delayed, in part, because of concern over rising construction costs and climate
21 change. For example:

22 ■ Westar Energy announced in December 2006 that it was deferring site
23 selection for a new 600 MW coal-fired power plant due to significant
24 increases in the facility's estimated capital cost of 20 to 40 percent, over
25 just 18 months. This prompted Westar's Chief Executive to warn: "When
26 equipment and construction cost estimates grow by \$200 million to \$400
27 million in 18 months, it's necessary to proceed with caution."¹⁶ As a
28 result, Westar Energy has suspended site selection for the coal-plant and is

¹⁴ Id., at page 6.

¹⁵ U.S. Securities and Exchange Commission Form 10-Q, Third Quarter of 2007, Idaho Power Company, at pages 49-50.

¹⁶ Available at

[http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/\\$file/122806%20coal%20plant%20final2.pdf](http://www.westarenergy.com/corp_com/corpcomm.nsf/F6BE1277A768F0E4862572690055581C/$file/122806%20coal%20plant%20final2.pdf).

1 considering other options, including building a natural gas plant, to meet
2 growing electricity demand. The company also explained that:

3 most major engineering firms and equipment manufacturers
4 of coal-fueled power plant equipment are at full production
5 capacity and yet are not indicating any plans to
6 significantly increase their production capability. As a
7 result, fewer manufacturers and suppliers are bidding on
8 new projects and equipment prices have escalated and
9 become unpredictable.¹⁷

- 10 ■ Tenaska Energy cancelled plans to build a coal-fired power plant in
11 Oklahoma in July 2007 because of rising steel and construction prices.
12 According to the Company's general manager of business development:

13 ... coal prices have gone up "dramatically" since Tenaska
14 started planning the project more than a year ago.

15 And coal plants are largely built with steel, so there's the
16 cost of the unit that we would build has gone up a lot... At
17 one point in our development, we had some of the steel and
18 equipment at some very attractive prices and that
19 equipment all of a sudden was not available.

20 We went immediately trying to buy additional equipment
21 and the pricing was so high, we looked at the price of the
22 power that would be produced because of those higher
23 prices and equipment and it just wouldn't be a prudent
24 business decision to build it.¹⁸

- 25 ■ Just last month, Associated Electric Cooperative, Inc., the wholesale
26 power supplier for 57 electric cooperatives in Missouri, Southeast Iowa,
27 and northeast Oklahoma, delayed its plans to build the Norborne 660 MW
28 coal-fired power plant due to due to increasing costs and other
29 uncertainties. According to AECI:

30 The Norborne project costs have significantly increased in
31 less than three years and are now estimated at \$2 billion
32 due to worldwide demand for engineering, skilled labor,
33 equipment and materials.

34 The U.S. Department of Agriculture Rural Utilities Service,
35 a traditional funding source for rural electric cooperatives,
36 is currently unable to finance baseload generation for
37 cooperatives. Although AECI's AA credit rating is one of

¹⁷ Id.

¹⁸ Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

1 the strongest ratings among all electric utilities nationally,
2 seeking private lending would further increase project
3 costs.

4 There also is increasing uncertainty in the regulatory
5 environment, and Congress continues to debate the
6 environmental and economic impact of reducing
7 greenhouse gas emissions, making the cost of reducing
8 carbon dioxide from power plants unknown.¹⁹

9 At the same time, AECI noted that it would continue to look at energy
10 efficiency initiatives, natural gas, renewable and nuclear resources to
11 address future generation needs.

12 ■ Rocky Mountain Power, a division of PacifiCorp, cancelled two proposed
13 coal plants in the fall of 2007. The Company explained the following in a
14 November 28, 2007 letter to the Public Service Commission of Utah:

15 Furthermore, due to the current uncertainty in the ability to
16 quantify in any meaningful way the cost of compliance
17 with potential federal CO₂ legislation, Bridger 5 as a
18 supercritical unit is no longer a viable option for 2014.
19 Within the last few months, it has become apparent that
20 Congress will enact some restriction upon carbon
21 emissions, but the project cost impact upon new coal
22 generation is currently within such a wide range as to make
23 meaningful risk assessment futile. On November 13, 2007,
24 the National Association of Regulatory Utility
25 Commissioners adopted its first resolution acknowledging
26 that climate change legislation addressing carbon emissions
27 will occur. Within the last few months, most of the planned
28 coal plants in the United States have been cancelled, denied
29 permits, or been involved in protracted litigation.
30 Accordingly, the Company submits that IPP 3, Bridger 5,
31 and the IGCC option at Jim Bridger are no longer viable
32 options for [its] 2012 RFP for the 2012 and 2014 time
33 frame, respectively.

34 **While the Company is not excluding new coal**
35 **generation ownership from its 20 year options, absent**
36 **some change in conditions, it cannot be determined at**
37 **this time whether new coal generation will satisfy the**
38 **least cost, least risk standards that would enable us to**

¹⁹ <http://www.aeci.org/NR20080303.aspx>.

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1 **consider it as a viable option within our ten year plans.**
2 (Emphasis added)²⁰

3 ▪ Xcel Energy announced in October 2007 that it was deferring indefinitely
4 its plans to build an IGCC plant in Colorado because the development
5 costs were higher than the utility originally expected.²¹

6 ▪ TXU cancelled 8 of 11 proposed coal-fired power plants in the spring of
7 2007 , in large part because of concern over global warming and the
8 potential for federal legislation restricting greenhouse gas emissions.²²

9 ▪ Four public power agencies in Florida suspended permitting activities for
10 the coal-fired Taylor Energy Center in the spring of 2007 because of
11 growing concerns about greenhouse gas emissions.²³

12 ▪ Tampa Electric cancelled a proposed integrated gasification combined
13 cycle plant (“IGCC”) in the fall of 2007 due to uncertainty related to CO₂
14 regulations, particularly capture and sequestration issues, and the potential
15 for related project cost increases. According to a press release, “Because
16 of the economic risk of these factors to customers and investors, Tampa
17 Electric believes it should not proceed with an IGCC project at this time,”
18 although it remains steadfast in its support of IGCC as a critical
19 component of future fuel diversity in Florida and the nation.

20 ▪ The Orlando Utilities Commission announced in November 2007 that it
21 was cancelling the coal gasification portion of a 285-megawatt integrated
22 gasification combined cycle (IGCC) facility at the Stanton Energy Center.
23 Construction will continue on the natural gas-fired combined cycle
24 generating unit. The Commission cited the impact of possible federal and
25 state regulations related to future emissions restrictions in the state of
26 Florida as the primary reason for terminating construction.²⁴

27 ▪ In June 2007, the Tondu Corp. announced that it was suspending plans to
28 build a planned 600 MW IGCC facility in Texas citing high costs and
29 other concerns related to technology and construction risks.²⁵

20 <http://www.psc.utah.gov/elec/05docs/0503547/55486NoticeWithdrawal.doc>.

21 Denver Business Journal, October 30, 2007.

22 See www.marketwatch.com/news/story/txu-reversal-coal-plant-emissions.

23 See www.taylorenergycenter.org/s_16.asp?n=40.

24 <http://www.ouc.com/news/releases/20071114-secb.htm>.

25 <http://www.reuters.com/article/companyNewsAndPR/idUSN1526955320070615>

1 **Q. Have you seen any instance where a participant in a jointly-owned coal-fired**
2 **power plant project has withdrawn because of concern over increasing**
3 **construction costs or the potential for future regulation of CO₂ emissions?**

4 A. Yes. GRE announced in September 2007 that it was withdrawing from the
5 proposed Big Stone II Project. According to GRE, four factors contributed most
6 prominently to the decision to withdraw, including uncertainty about changes in
7 environmental requirements and new technology and the fact that “The cost of
8 Big Stone II has increased due to inflation and project delays.”²⁶

9 **Q. Have any proposed coal-fired generating projects been rejected by state**
10 **regulatory commissions due, in whole or in part, to concerns over increasing**
11 **construction costs or the potential for federal regulation of greenhouse gas**
12 **emissions?**

13 A. Yes. Although some new coal-fired power plant projects have been approved by
14 state regulatory commissions and agencies during 2007, since last December
15 proposed coal-fired power plant projects have been rejected by the Oregon Public
16 Utility Commission, the Florida Public Service Commission, and the Oklahoma
17 Corporation Commission. The North Carolina Utilities Commission rejected one
18 of the two coal-fired plants proposed by Duke Energy Carolinas for its Cliffside
19 Project. The Kansas Department of Health and Environment also has recently
20 rejected proposed coal-fired power plants.

21 The decision of the Florida Public Service Commission in denying approval for
22 the 1,960 MW Glades Power Project was based on concern over the uncertainties
23 over plant costs, coal and natural gas prices, and future environmental costs,
24 including carbon allowance costs.²⁷ In addition, the Oklahoma Corporation

²⁶ See www.greatriverenergy.com/press/news/091707_big_stone_ii.html.

²⁷ Order No. PSC-07-0557-FOF-EI, Docket No. 070098-EI, July 2, 2007.

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1 Commission voted in September of this year to reject Public Service of
2 Oklahoma’s application to build a new coal-fired power plant.²⁸

3 The Minnesota Public Utilities Commission also has refused to approve an
4 agreement under which Xcel Energy would have purchased power from a
5 proposed IGCC facility due to concerns over the uncertainties surrounding the
6 plant’s estimated construction and operating costs and operating and financial
7 risks.²⁹

8 On October 18, 2007, the Kansas Department of Health and Environment rejected
9 an application to build two 700 MW coal-fired units at an existing power plant
10 site. In a prepared statement explaining the basis for this decision, Rod Bremby,
11 Kansas’s secretary of health and environment noted that “I believe it would be
12 irresponsible to ignore emerging information about the contribution of carbon
13 dioxide and other greenhouse gases to climate change and the potential harm to
14 our environment and health if we do nothing.”³⁰

15 **Q. Has any lending agency of the U.S. government decided not to loan funds for**
16 **new coal-fired power plants?**

17 A. Yes. The Rural Utilities Service of the U.S. Department of Agriculture
18 announced in early March 2008 that it is suspending the program through which it
19 makes loans to rural cooperatives to build new coal-fired power plants.³¹ In a
20 letter to Congress, the Administrator of Utility Programs for the Department of
21 Agriculture indicated that loans for new base load generation plants would not be
22 made until the RUS and the federal Office of Management and Budget can
23 develop a subsidy rate to reflect the risks associated with the construction of such
24 plants.³²

²⁸ Cause No. PUD 200700012 signed Order No. 545240, October 2007.

²⁹ Order in Docket No. E-6472/M-05-1993, dated August 30, 2007, at pages 16-19.

³⁰ See www.kansascity.com/105/story/323833.html.

³¹ <http://www.washingtonpost.com/wp-dyn/content/article/2008/03/12/AR2008031203784.html>.

³² <http://oversight.house.gov/documents/20080312104146.pdf>.

1 **Q. Is it important to evaluate the uncertainties and risks associated with**
2 **alternatives to the Big Stone II Project as well?**

3 A. Yes. The risks associated with building natural gas-fired alternatives include
4 potential CO₂ emissions costs, possible capital cost escalation and fuel price
5 uncertainty and volatility.

6 Renewable alternatives and energy efficiency also have some uncertainties and
7 risks. These include potential capital cost escalation, contract uncertainty and
8 customer participation uncertainty.

9 Unfortunately, OTP and MDU have focused on the uncertainties and risks
10 associated with the alternatives and have essentially ignored the significant
11 uncertainties and risks associated with pursuing the Big Stone II Project. Indeed,
12 as we look over the series of analyses that OTP and MDU have presented to this
13 Commission and the Minnesota Public Utilities Commission since late 2006, they
14 reflect a clear pattern of minimizing the potential increases in the costs of building
15 and operating the Big Stone II Project while repeatedly raising the costs of
16 building and operating each of the alternatives to the Project. This has the
17 obvious effect of biasing their economic analyses in favor of Big Stone II.

18 **4. OTP and MDU Have Not Adequately Considered The Risk Of Further**
19 **Increases In The Estimated Capital Cost Of The Big Stone II Project**

20 **Q. What estimated capital costs for the Big Stone II Project have OTP and**
21 **MDU used in their recent modeling analyses?**

22 A. According to Applicant witness Rolfes, the currently estimated cost of a 500 MW
23 ultra supercritical Big Stone II Project is \$1.272 billion.³³ The currently estimated
24 cost for a 580 MW unit is \$1.411 billion.

³³ OTP/MDU Exhibit 324, at page 1, lines 20-22.

1 **Q. What is the currently scheduled commercial operation date (“COD”) that**
2 **OTP and MDU have used in their new modeling analyses?**

3 A. The currently scheduled COD date for Big Stone II is the summer of 2013.³⁴

4 **Q. How did OTP and MDU determine the currently estimated cost and COD for**
5 **the Big Stone II Project that they have used in their new modeling analyses?**

6 A. The Big Stone II Co-owners have explained the derivation of the current project
7 cost estimates for 500 MW and 580 MW sized plants as follows:

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REDACTED

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³⁴ Id., at page 1, lines 16-18.

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3 **Q. What is the current status of the Big Stone II Project?**

4 A. Although some work may have been undertaken, it appears that no major design
5 or procurement activities have been completed. As of November 2007 the Big
6 Stone II Co-owners intended [**REDACTED**

7] ³⁶ Now it appears that Black & Veatch engineering [**REDACTED**
8] ³⁷

9 **Q. Have OTP and MDU reflected in their recent modeling analyses any**
10 **uncertainty regarding the ultimate cost or COD of the Big Stone II Project?**

11 A. The current Big Stone II Project cost estimate does include a limited contingency
12 allowance. However, MDU has not prepared any sensitivity analyses to examine
13 the impact of larger increases in Big Stone II Project costs that would exceed this
14 limited contingency. OTP has presented one, inadequate, modeling analysis that
15 reflects a 10 percent increase in the project's cost.

16 **Q. Have you seen any evidence that OTP and MDU are losing confidence in the**
17 **current Big Stone II Project cost and schedule estimate?**

18 A. [**REDACTED**

19] ³⁸ However, the Big Stone II Applicants
20 also noted that [**REDACTED**] ³⁹

³⁵ *Memorandum to Big Stone II Project Data Disk*, William Swanson, dated 11/7/2007, at Bates Page Number OTP0010464. Included in Exhibit DAS-S6 (Confidential).

³⁶ Id.

³⁷ Black & Veatch Conference Memorandum #018 – BSPII – B&V Meeting of February 14, 2008, at Bates Page Number OTP0011083. Included in Exhibit DAS-S6 (Confidential).

³⁸ Big Stone II Applicants' Response to Joint Intervenors' Information Request No. 243 in Minnesota PUC CON Dockets, at Bates Page Number OTP0008037. Included in Exhibit DAS-S6 (Confidential).

³⁹ Id.

1 **Q. When do OTP and MDU intend to produce a new cost estimate for the Big**
2 **Stone II Project?**

3 A. [

4 **REDACTED**

5]⁴⁰

6 Unfortunately, this will be after this Commission has decided whether to grant
7 Advanced Determination of Prudence for the Big Stone II Project.

8 **Q. Is it reasonable to expect that the estimated and/or ultimate cost of the**
9 **project will be higher than OTP and MDU now estimate?**

10 A. Yes. The costs of building power plants have soared in recent years as a result of
11 the worldwide demand for power plant design and construction resources and
12 commodities. There is no reason to expect that plant costs will not continue to
13 rise during the years when the detailed engineering, procurement and construction
14 of the Big Stone II Project will be underway. This is especially true given the
15 extremely early stage of the engineering and procurement for the project.

16 For example, Duke Energy Carolinas' originally estimated cost for the 1600 MW
17 two unit coal-fired Cliffside Project was approximately \$2 billion. In the fall of
18 2006, Duke announced that the cost of the project had increased by approximately
19 47 percent (\$1 billion). After the project had been downsized because the North
20 Carolina Utilities Commission refused to grant a permit for two units, Duke
21 announced that the cost of that single unit would be about \$1.53 billion, not
22 including financing costs. In late May 2007, Duke announced that the cost of
23 building that single unit had increased by about another 20 percent. As a result,
24 the estimated cost of the one unit that Duke is building at Cliffside is now \$1.8
25 billion, exclusive of financing costs. Thus, the single Cliffside unit is now
26 expected to cost almost as much as Duke originally estimated for a two unit plant.

⁴⁰ Black & Veatch Conference Memorandum #018 – BSPII – B&V Meeting of February 14, 2008, at Bates Page Number OTP0011083. Included in Exhibit DAS-S6 (Confidential).

1 **Q. Did Duke explain to the North Carolina Utilities Commission the reasons for**
2 **the skyrocketing cost of the Cliffside Project?**

3 A. Yes. In testimony filed at the North Carolina Utilities Commission on November
4 29, 2006, Duke Energy Carolinas emphasized that the competition for resources
5 had had a significant impact on the costs of building new power plants:

6 The costs of new power plants have escalated very rapidly. This
7 effect appears to be broad based affecting many types of power
8 plants to some degree. One key steel price index has doubled over
9 the last twelve months alone. This reflects global trends as steel is
10 traded internationally and there is international competition among
11 power plant suppliers. Higher steel and other input prices broadly
12 affects power plant capital costs. A key driving force is a very
13 large boom in U.S. demand for coal power plants which in turn has
14 resulted from unexpectedly strong U.S. electricity demand growth
15 and high natural gas prices. Most integrated U.S. utilities have
16 decided to pursue coal power plants as a key component of their
17 capacity expansion plan. In addition, many foreign companies are
18 also expected to add large amounts of new coal power plant
19 capacity. This global boom is straining supply. Since coal power
20 plant equipment suppliers and bidders also supply other types of
21 plants, there is a spill over effect to other types of electric
22 generating plants such as combined cycle plants.⁴¹

23 Duke further noted that the actual coal power plant capital costs as reported by
24 plants already under construction were exceeding government estimates of capital
25 costs by “a wide margin (i.e., 35 to 40 percent).”⁴² Additionally, according to
26 Duke, currently announced power plants were appearing to face another
27 approximate 40 percent increase in costs.” Thus, new coal-fired power plant
28 capital costs had increased approximately 90 to 100 percent between 2002 and
29 late 2006.

⁴¹ Direct Testimony of Judah Rose for Duke Energy Carolinas, North Carolina Utilities Commission Docket No. E-7, SUB 790, at page 4, lines 2-14, available on the North Carolina Utilities Commission website.

⁴² Id., at page 6, lines 5-9, and page 12, lines 11-16.

1 **Q. Have other coal-fired plant projects experienced similar cost increases?**

2 A. Yes. A large number of projects have announced significant construction cost
3 increases over the past few years. The following examples are illustrative of the
4 increases in estimated construction costs that have been experienced by some
5 coal-fired power plant projects in recent years:

- 6 ▪ The cost of Westar’s proposed coal-fired plant in Kansas, originally
7 estimated at \$1 billion, increased by 20 percent to 40 percent, over just 18
8 months.
- 9 ▪ Similarly, the estimated cost of the now-cancelled Taylor Energy Center
10 in Florida increased by 25 percent, \$400 million, in just 17 months
11 between November 2005 and March 2007.
- 12 ▪ The estimated cost of the Little Gypsy Repowering Project (gas to coal) in
13 Louisiana increased by 55 percent between announcement of the project in
14 April 2007 and the filing of a request for a license to build in July 2007.
- 15 ▪ The cost of Sierra Pacific Resource’s proposed 1,500 MW Ely Energy
16 Center has increased by more than 30 percent since it was first announced
17 in 2006.
- 18 ▪ The estimated cost of the 960 MW AMP-Ohio plant has increased from
19 approximately \$1.2 billion in 2005 to nearly \$3 billion in January 2008.
20 This new estimate represents a cost of more than \$3,000 per kW, not
21 including financing costs.

22 **Q. What are the sources of the worldwide competition for power plant design
23 and construction resources, commodities and equipment?**

24 A. The worldwide competition is driven mainly by huge demands for power plants in
25 China and India, by a rapidly increasing demand for power plants and power plant
26 pollution control modifications in the United States required to meet SO₂ and NO_x
27 emissions standards, and by the competition for resources from the petroleum
28 refining industry. The demand for labor and resource to rebuild the Gulf Coast
29 area after Hurricanes Katrina and Rita hit in 2005 also has contributed to rising
30 costs for construction labor and materials. The anticipated construction of new
31 nuclear power plants also is expected to compete for limited power plant design
32 and construction resources, manufacturing capacity and commodities.

1 **Q. Is it commonly accepted that domestic United States and worldwide**
2 **competition for power plant design and construction resources, commodities**
3 **and manufacturing have led to these significant increases in power plant**
4 **construction costs in recent years?**

5 A. Yes. The worldwide competition for power plant resources is generally
6 recognized as the driving force for skyrocketing construction costs. For example,
7 a June 2007 report by Standard & Poor's, *Increasing Construction Costs Could*
8 *Hamper U.S. Utilities' Plan to Build New Power Generation*, found that:

9 As a result of declining reserve margins in some U.S. regions ...
10 brought about by a sustained growth of the economy, the domestic
11 power industry is in the midst of an expansion. Standing in the way
12 are capital costs of new generation that have risen substantially
13 over the past three years. Cost pressures have been caused by
14 demands of global infrastructure expansion. In the domestic power
15 industry, cost pressures have arisen from higher demand for
16 pollution control equipment, expansion of the transmission grid,
17 and new generation. While the industry has experienced buildout
18 cycles in the past, what makes the current environment different is
19 the supply-side resource challenges faced by the construction
20 industry. A confluence of resource limitations have contributed,
21 which Standard & Poors' Rating Services broadly classifies under
22 the following categories

- 23 ■ Global demand for commodities
- 24 ■ Material and equipment supply
- 25 ■ Relative inexperience of new labor force, and
- 26 ■ Contractor availability

27 The power industry has seen capital costs for new generation climb
28 by more than 50% in the past three years, with more than 70% of
29 this increase resulting from engineering, procurement and
30 construction (EPC) costs. Continuing demand, both domestic and

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1 international, for EPC services will likely keep costs at elevated
2 levels.⁴³

3 Standard & Poor’s warned, therefore, that “it is possible that with declining
4 reserve margins, utilities could end up building generation at a time when labor
5 and materials shortages cause capital costs to rise, well north of \$2,500 per kW
6 for supercritical coal plants and approaching \$1,000 per kW for combined-cycle
7 gas turbines (CCGT).”⁴⁴

8 Standard & Poor’s also concluded that “as capital costs rise, energy efficiency and
9 demand side management already important from a climate change perspective,
10 become even more crucial as any reduction in demand will mean lower
11 requirements for new capacity.”⁴⁵

12 Price increases have become so dramatic that the president of the Siemens Power
13 Generation Group told the New York Times that “There’s real sticker shock out
14 there.”⁴⁶ He also estimated that in the last 18 months, the price of a coal-fired
15 power plant has risen 25 to 30 percent. Similarly, in its 2007 Application to the
16 Ohio Power Siting Board, American Municipal Power-Ohio noted that the price
17 increases currently being experienced in the expected construction costs of coal
18 based electric generation were “staggering.”⁴⁷

19 Finally, a September 2007 report on *Rising Utility Construction Costs* prepared by
20 the Brattle Group for the EDISON Foundation of the Edison Electric Institute
21 similarly concluded that:

22 Construction costs for electric utility investments have risen
23 sharply over the past several years, due to factors beyond the
24 industry’s control. Increased prices for material and manufactured

⁴³ *Increasing Construction Costs Could Hamper U.S. Utilities’ Plans to Build New Power Generation*, Standard & Poor’s Rating Services, June 12, 2007, at page 1. A copy of this report is included as Exhibit DAS-S2.

⁴⁴ Id.

⁴⁵ id.

⁴⁶ “Costs Surge for Building Power Plants, *New York Times*, July 10, 2007.

⁴⁷ AMP-Ohio’s May 2007 Application to the Ohio Power Siting Board, Section OAC 4906-13-05, at page 4.

1 components, rising wages, and a tighter market for construction
2 project management services have contributed to an across-the-
3 board increase in the costs of investing in utility infrastructure.
4 These higher costs show no immediate signs of abating.⁴⁸

5 The report further found that:

- 6 ▪ Dramatically increased raw materials prices (e.g., steel, cement) have
7 increased construction cost directly and indirectly through the higher cost
8 of manufactured components common in utility infrastructure projects.
9 These cost increases have primarily been due to high global demand for
10 commodities and manufactured goods, higher production and
11 transportation costs (in part owing to high fuel prices), and a weakening
12 U.S. dollar.
- 13 ▪ Increased labor costs are a smaller contributor to increased utility
14 construction costs, although that contribution may rise in the future as
15 large construction projects across the country raise the demand for
16 specialized and skilled labor over current or project supply. There also is a
17 growing backlog of project contracts at large engineering, procurement
18 and construction (EPC) firms, and construction management bids have
19 begun to rise as a result. Although it is not possible to quantify the impact
20 on future project bids by EPC, it is reasonable to assume that bids will
21 become less cost-competitive as new construction projects are added to the
22 queue.
- 23 ▪ The price increases experienced over the past several years have affected
24 all electric sector investment costs. In the generation sector, all
25 technologies have experienced substantial cost increases in the past three
26 years, from coal plants to windpower projects.... As a result of these cost
27 increases, the levelized capital cost component of baseload coal and
28 nuclear plants has risen by \$20/MWh or more – substantially narrowing
29 coal’s overall cost advantages over natural gas-fired combined-cycle
30 plants – and thus limiting some of the cost-reduction benefits expected
31 from expanding the solid-fuel fleet.
- 32 ▪ The rapid increases experienced in utility construction costs have raised
33 the price of recently completed infrastructure projects, but the impact has
34 been mitigated somewhat to the extent that construction or materials
35 acquisition preceded the most recent price increases. The impact of rising
36 costs has a more dramatic impact on the estimated cost of proposed utility
37 infrastructure projects, which fully incorporates recent price trends. This

⁴⁸ *Rising Utility Construction Costs: Sources and Impacts*, prepared by The Brattle Group for the EDISON Foundation, September 2007, at page 31. A copy of this report is included as Exhibit DAS-S3.

1 has raised significant concerns that the next wave of utility investments
2 may be imperiled by the high cost environment. These rising construction
3 costs have also motivated utilities and regulators to more actively pursue
4 energy efficiency and demand response initiatives to reduce the future rate
5 impacts on consumers.⁴⁹

6 **Q. Is it reasonable to expect that the worldwide competition for power plant**
7 **design and construction resources will continue to lead to further**
8 **construction cost increases in future years?**

9 A. Yes. I have seen no evidence that these long term factors will abate at any point
10 in the foreseeable future. For example, an October 2007 report by the consulting
11 engineering firm of Burns and Roe for the City of Cleveland Division of
12 Cleveland Public Power noted that it is difficult to predict the escalation of future
13 power plant costs and expressed concern that “India is on the threshold of
14 beginning a rapid expansion in the upcoming years will place additional pressure
15 on the availability of raw materials, shop fabrication space and available work
16 force for engineering, site management staff and field labor and supervision.”⁵⁰

17 **Q. Do the Big Stone II Applicants, including OTP and MDU, agree that these**
18 **are the factors that have been driving the significant increases that have**
19 **recently been experienced in the estimated costs of building new coal-fired**
20 **power plants?**

21 A. Yes. In his 2006 testimony in the Minnesota PUC CON Dockets, Big Stone II
22 Applicant witness Trout identified the following as among the factors that have
23 led to increases in the costs of building new power plants:

24 Since the initial [Big Stone II cost] estimate was prepared in 2004,
25 the power generation industry has experienced significant pricing
26 increases for various commodities including steel, alloy piping,
27 cable and wire, and other critical commodities. These have

⁴⁹ Id., at pages 1-3.

⁵⁰ *Consulting Engineer’s Report for the American Municipal Power Generating Station located in Meigs County, Ohio*, for the Division of Cleveland Public Power, Burns and Roe Enterprises, Inc., October 16, 2007, at page 10-9.

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1 contributed to a constantly changing market for commodities and
2 power plant equipment....

3 * * * *

4 • Major construction commodities have increased 30% to
5 80% during the last two years.

6 • Labor rate escalation is currently double what it was two
7 years ago.

8 The global demands (the governments of China and India, for
9 example) for huge expansion in the electricity production sectors
10 will impact equipment prices and creates raw material and
11 fabrication facility (shop space) shortages worldwide for all types
12 of energy production projects. The U.S. electricity production
13 industry announced multiple large projects for development and
14 construction, some of which have supply contracts which have
15 recently been awarded. The energy and process markets are
16 experiencing tremendous growth at the same time.

17 • Suppliers and Subcontractors that downsized after the
18 market collapsed in 2001 are challenged to grow their
19 capacity and workforce.

20 • Continuously increasing costs and longer delivery times for
21 raw materials are influencing engineered equipment costs
22 and commodity purchases.

23 Increased costs for fuel have caused unexpected increases in
24 fabrication and transportation costs for delivery of fabricated
25 materials, as well as higher construction costs to build this
26 project.⁵¹

27 In addition, Black & Veatch prepared a *Big Stone II Project Perspective Briefing*
28 *Book for Owners' CEOs – Supplemental materials*, in the spring of 2007 that
29 indicated the following concerning power plant construction costs and schedules:

⁵¹ Applicants' Exhibit 33 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 27, line 20, to page 29, line 14.

1 **Q. Have OTP and MDU assumed any increases in the cost of building the Big**
2 **Stone II Project as a result of the recent project hiatus or suspension and the**
3 **result delay of more than one year?**

4 A. OTP and MDU have assumed that the cost of the Project will increase by the
5 relative minor amount of 6 percent due to an additional year's escalation of costs.
6 However, they have not reflected any major cost increases due to the worldwide
7 competition I have described above. In fact, OTP and MDU have assumed they
8 will be able to *reduce* the estimated cost of the Project by about [REDACTED] by
9 achieving unspecified cost savings.⁵⁶ I have seen no evidence that provides any
10 justification for believing that the Big Stone II Project will be able to avoid the
11 significant delays and cost increases that numerous other projects have
12 experienced in the past two to three years and that have been discussed by [
13 **REDACTED**]

14 **Q. Do you have any comment on the claim by Mr. Rolfes that the current Big**
15 **Stone II cost estimates “are well within the range of what other projects are**
16 **experiencing and what others are using in their projects?”⁵⁷**

17 A. Yes. I do not agree with Mr. Rolfes' claim for a number of reasons. First, as the
18 evidence in support of Mr. Rolfes' claim OTP has provided only a single page of
19 estimated construction costs for some of the proposed coal-fired power plants.
20 However, there is no evidence that the construction cost estimates included on
21 this page are current or are out-of-date. Indeed, looking over the table, it appears
22 that only a few of the cost estimates were prepared since last summer. Most are
23 from 2006 and the first half of 2007.

24 Moreover, there is no evidence that the estimated costs of building the coal-plants
25 listed on this page won't themselves increase significantly as a result of the same
26 domestic and international competition for power plant design and construction

⁵⁶ *Memorandum to Big Stone II Project Data Disk*, William Swanson, dated 11/7/2007, at Bates Page Number OTP0010464. Included in Exhibit DAS-S6 (Confidential).

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1 resources that I have discussed. For example, when assessing the currently
2 estimated cost of the Holcomb coal plants in Kansas, proposed by Sunflower
3 Electric Coop, Innovest Strategic Value Advisors, noted that:

4 In addition to regulatory and stakeholder opposition, rising
5 construction costs continue to derail the construction of new coal-
6 fired power plants throughout the United States. Although the
7 proposed Holcomb expansion is currently estimated to cost \$3.6
8 billion, potential delays coupled with increasing costs of
9 construction will likely result in significant upward adjustments in
10 cost projections. This will ultimately result in increased electricity
11 rates for Sunflower's customers.⁵⁸

12 In addition, the estimated plant construction costs listed in OTP's table do not
13 appear to have been adjusted for size. Thus, the costs of a number of plants, such
14 as Longview Power and the Holcomb Expansion project would be substantially
15 higher than the current Big Stone II cost estimate if an adjustment were made to
16 reflect the substantially larger sizes of each of these projects (i.e., 695 MW for the
17 Longview Power plant with a currently cost of \$2590/kW and 750 MW for the
18 Holcomb Expansion plants with a currently estimated cost of \$2500/kW).

19 For example, using the same EPRI formula that Mr. Rolfes has used, the size
20 adjusted cost of a 500 MW plant using the Longview Project cost estimate would
21 be \$1.43 billion, or approximately 12 percent higher than the current \$1.272
22 billion estimate for a 500 MW Big Stone II. The size adjusted cost of a 580 MW
23 coal plant using the current Longview Project estimate would be \$1.59 billion or
24 12 percent higher than the current \$1.411 billion estimate for a 580 MW Big
25 Stone II. This example suggests that the current Big Stone II cost estimates are
26 too low. It also is important to remember that it is possible, even quite likely, that
27 the cost of the Longview Power plant will increase further.

⁵⁷ OTP/MDU Exhibit 324, at page 5, lines 5-8.

⁵⁸ *Sunflower Electric Power: Carbon Risks Outweigh Benefits of Holcomb Expansion, A Report by Innovest Strategic Value Advisors, March 2008, at page 5.*

1 Finally, OTP’s table does not include the estimated costs of all proposed coal-
2 fired power plants. For example, it does not include the proposed 960 MW AMP-
3 Ohio plant which is currently projected to cost approximately \$3 billion.
4 Adjusting for economies of scale using the EPRI formula, the cost of a 500 MW
5 plant based on the AMP-Ohio estimate would be \$1.9 billion, or 49 percent higher
6 than the current \$1.272 billion estimated cost of a 500 MW Big Stone II. The cost
7 of a 580 MW plant based on the AMP-Ohio would be \$2.1 billion, also 49 percent
8 higher than the current \$1.411 billion 580 MW Big Stone II.

9 **Q. Mr. Rolfes has testified that you pointed to Duke Energy’s recently approved**
10 **800 MW Cliffside project as an example of how much a super-critical**
11 **baseload plant is likely to cost.⁵⁹ Is that correct?**

12 A. No. We provided the Cliffside Plant solely as an example of how much the
13 estimated costs of coal-fired power plants had increased over the past few years.

14 **Q. Mr. Rolfes also testifies that, when adjusted for economies of scale, “a**
15 **comparison of Big Stone II with the Duke Cliffside plant actually lends**
16 **credence to the fact that our estimate is in line with what the rest of the**
17 **industry is seeing.”⁶⁰ Does Mr. Rolfes present a complete and accurate**
18 **comparison between the Cliffside Project and Big Stone II?**

19 A. No. Mr. Rolfes simplistic comparison ignores the fact that Duke Energy Carolinas
20 conducted much, if not all, of the procurement of the main plant equipment for the
21 Cliffside Project at the end of 2006 and early 2007. In contrast, it is unlikely that
22 the rebidding or renegotiation of the past bids for equipment for Big Stone II will
23 be completed until later this year or even early into the next year. Given the
24 “surge” in power plant labor, commodity and equipment prices in recent years, it
25 is reasonable to expect that the costs of the major Big Stone II plant equipment

⁵⁹ OTP/MDU Exhibit 324, at page 6, lines 9-11.

⁶⁰ Id., at page 6, lines 14-17.

1 will be much higher than the prices paid by Duke Energy Carolinas several years
2 ago.

3 The Cliffside Project also is set to begin construction in the near future and to be
4 completed by the summer of 2012. Thus construction of the Cliffside Project will
5 be at least a year ahead of that of Big Stone II. This means that the commodity
6 and labor costs at Cliffside are likely to be lower than those at Big Stone II. And
7 this even ignores any premium that may have to be paid to attract experienced
8 construction personnel to South Dakota to work on Big Stone II. For all of these
9 reasons, it can be expected that the cost of the Big Stone II Project will exceed the
10 size adjusted cost of the Cliffside Project presented by Mr. Rolfes.

11 **Q. Is it reasonable to assume that the increased competition for power plant**
12 **design and construction resources, commodities and manufacturing capacity**
13 **factors that has led to the significant increases in power plant capital costs**
14 **also will lead to construction delays?**

15 A. Yes.

16 **Q. Have the Big Stone II Applicants identified any specific factors which could**
17 **prevent the Project from achieving the scheduled June 2013 in-service date?**

18 A. Yes. [

19 **REDACTED**

20]. These

21 activities include:

22 ▪ [

23 ▪ **REDACTED**

24 ▪]⁶¹

⁶¹ Big Stone II Applicants' Confidential Response to Joint Intervenors Information Request No. 243 in Minnesota PUC CON Dockets, at Bates Page Number OTP0008060. Included in Exhibit DAS-S6 (Confidential).

1 **Q. In fact, has Black & Veatch engineering been re-engaged to work on the Big**
2 **Stone II Project?**

3 A. [

4 **REDACTED**

5

6

⁶³

].

7 **Q. Is it reasonable to expect that this [] in re-engaging Black & Veatch**
8 **engineering to continue design and procurement work will have an impact on**
9 **the projected COD for the Big Stone II Project?**

10 A. Yes. [

REDACTED

11

].

12 **Q. Is the Big Stone II Project team confident that Black & Veatch resources will be**
13 **available when a decision is made to reengage them for the Big Stone II Project?**

14 A. The notes of the February 14, 2008 Project team meeting indicate that Mr. Rolfes
15 said [**REDACTED**

16

]⁶⁴

17 **Q. Have you seen any other evidence that suggests that the Big Stone II Project**
18 **will not have a COD in the summer of 2013, as Mr. Rolfes has testified?**

19 A. [

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21

22

REDACTED

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⁶³ Bates Page Number OTP0011083. Included in Exhibit DAS-S6 (Confidential).

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Q. Have you seen any evidence that suggests the possible magnitude of the increased costs that might be experienced when the contract bids for the Big Stone II Project are rebid or negotiated?

4

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A. No. However, [

7

REDACTED

8

].⁶⁶ For example, in its IRP filed in November 2007 in

9

Colorado, Xcel Energy noted that “Boiler unit costs are reported to have increased

10

50 to 80% in the last year.”⁶⁷

11

Q. In your opinion, is it prudent for OTP and MDU to ignore the potential for significant Big Stone II Project cost increases and schedule delays in their recent modeling and economic analyses?

12

13

14

A. No. Although the current project cost estimate does include some contingencies, we believe that given the dramatic spike in coal plant construction costs over the last few years, it is reasonable to assume that the Project’s construction cost may be substantially higher than OTP and MDU now acknowledge and that the Project’s COD may be later than OTP and MDU now admit. This is especially true because all project contracts have not been let and many detailed design and all construction activities have not started. It is important to remember that the cost of this project already rose by more than 25 percent between 2004 and July

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⁶⁴ Black & Veatch Conference Memorandum #018 – BSPII – B&V Meeting of February 14, 2008, at Bates Page Number OTP0011084. Included in Exhibit DAS-S6 (Confidential).

⁶⁵ Big Stone II CEO Meeting, January 18, 2008, at Bates Page Number OTP0011075. Included in Exhibit DAS-S6 (Confidential).

⁶⁶ For example, see Big Stone II Applicants’ Response to Joint Intervenors’ Information Request Nos. 146-151 in Minnesota PUC CON Dockets, at Bates Page Numbers OTP0006946, 6997, and 6949.

⁶⁷ Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-36.

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1 2006.⁶⁸ OTP and MDU have presented no evidence that the forces that caused that
2 major price increase (and that are still causing “staggering” price increases around
3 the nation) will not lead to further cost increases for the Big Stone II Project in the
4 coming years.

5 In fact, even Applicant witnesses Rolfes and Trout have not foreclosed the
6 potential for further increases in the Project’s estimated capital cost. For example,
7 Mr. Trout has further noted that future changes in the estimated cost for the Big
8 Stone II Project are “becoming more dependent on outside forces” some of which
9 he describes in his October 2, 2006 Testimony.⁶⁹ He further noted that “the Big
10 Stone II Co-owners have not been in a position realistically or reasonably to “lock
11 in” the prices for a substantial portion of the major cost components of Big Stone
12 Unit II” and that “Until they do so, the project budget will be subject to further
13 refinement.”⁷⁰

14 **Q. Have you seen any other evidence that suggests that the Big Stone II**
15 **Applicants, including OTP and MDU, do not have complete confidence in**
16 **their current cost estimate?**

17 A. Yes. During the recent CON hearings in Minnesota, OTP witness Uggerud said
18 that OTP is not willing to commit to limit its rate recovery from the Big Stone II
19 project to its share of the current project capital cost estimate.⁷¹ The Big Stone II
20 Applicants similarly expressed their opposition to a proposal by the Minnesota
21 Department of Commerce that OTP agree not to be able to include in its rates any

⁶⁸ The estimated cost of the Project actually increased by significantly more than 25 percent in July 2006 but OTP and MDU offset much of that increase by assuming that substantial savings can be achieved in design and construction.

⁶⁹ Applicants’ Exhibit 33 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 24, lines 19-20, and at page 27, line 18, to page 28, line 14.

⁷⁰ Applicants’ Exhibit 33 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 28, lines 14-17.

⁷¹ Volume 1 of the Hearing Transcript of January 23, 2008 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 27, lines 1 through 19.

1 capital costs that exceed the present day estimates.⁷² Obviously, OTP does not
2 have sufficient confidence in its current cost estimate that it is willing to place
3 shareholders at risk rather than ratepayers.

4 **Q. Is it reasonable to expect that OTP and MDU could have updated their**
5 **Project capital cost estimate at some point in the past year to reflect the**
6 **industry-wide developments and cost trends you have described?**

7 A. Yes. It was not necessary for OTP and MDU to wait until [**REDACTED**]
8 to prepare a Big Stone II Project cost estimate and schedule update. Such
9 information should have been prepared so that the Commission would have the
10 most up-to-date information when it deliberates whether to grant an Advanced
11 Determination of Prudence for OTP and MDU's investments in the proposed
12 Project. Even if it had cost another \$1 million to prepare a new estimate, that
13 would have been a relatively minor expenditure considering the potential cost of
14 the Project may exceed \$1.5 to \$2 billion.

15 OTP and MDU should be required to provide such a new cost and schedule
16 estimate to this Commission. The two companies want this Commission to grant
17 an Advanced Determination of Prudence, which would give them a blank check
18 for recovering future Big Stone II expenditures. Given the cost increases that have
19 been experienced by other power plant projects, and the continuing factors that
20 have led to those increases, this Advanced Determination of Prudence should not
21 be based on a cost estimate that is nearly two years old. To do so would place
22 ratepayers at great risk considering the real probability that the cost of Big Stone
23 II will exceed the current estimate, perhaps by a significant amount.

⁷² Applicants' Brief in Support of Certificate of Need, MPUC Docket Nos. CN-05-619 and TR-05-1275, dated February 6, 2008, at page 42.

1 **Q. How should OTP and MDU have reflected the potential for further increases**
2 **in the cost of the Big Stone II Project in their modeling analyses?**

3 A. In order to more fully evaluate the risks of continuing with the proposed project,
4 OTP and MDU should have prepared sensitivity studies that examined the relative
5 economics of the Big Stone II Project against alternatives assuming that the
6 capital cost of the project is substantially higher than they now estimate and that
7 the Project may not be in-service in June 2013.

8 For example, OTP and MDU could have prepared sensitivity analyses in their
9 modeling analyses that reflected capital costs that are 10, 20 percent and/or 40
10 percent higher than their current estimated costs for the Big Stone II Project. It is
11 not unreasonable to expect such additional cost increases at the Project in light of
12 the industry-wide experience and the expectation that worldwide demand will
13 continue to be a driving force for rising prices.

14 **Q. Have OTP and MDU performed sensitivities around the current Big Stone II**
15 **cost estimates, as Mr. Rolfes testifies?**⁷³

16 A. MDU has not presented any sensitivities to this Commission or the Minnesota
17 PUC that have reflected any higher costs for the Big Stone II Project than the
18 currently estimated construction cost. OTP has presented a single scenario in this
19 proceeding that reflects a minor 10 percent increase in the Project's construction
20 cost. However, OTP biases the analysis by failing to include any significant CO₂
21 prices in its modeling, as I will discuss in the next section of this testimony.

22 **Q. Is it reasonable to expect that market conditions also will lead to increases in**
23 **the estimated costs of other supply-side alternatives such as natural gas-fired,**
24 **wind or biomass facilities?**

25 A. Yes. However, it is not necessarily reasonable to expect that all of the alternative
26 technologies will experience the same cost increases as a coal-fired project like

⁷³ OTP/MDU Exhibit 324, at page 5, line 16, to page 6, line 6.

1 Big Stone II. This is because coal-fired power plants are more capital intensive
2 than other technologies such as natural gas plants, reflecting larger amounts of
3 steel, etc., and greater numbers of person-hours to build. In fact, even OTP has
4 assumed that natural gas-fired simple cycle and combined cycle plants will
5 experience lower escalation than the Big Stone II Project.⁷⁴

6 **Q. What impact would higher coal-plant capital costs have on the relative**
7 **economics of energy efficiency as compared to the Big Stone II Project?**

8 A. I have seen no evidence that the same worldwide demand for power plant
9 resources has led to significant increase in the costs of energy efficiency
10 measures. Therefore, it is reasonable to expect that higher coal-plant capital costs
11 increase the relative economics and attractiveness of energy efficiency.

12 **5. The Big Stone II Applicants Have Not Adequately Considered The**
13 **Risks Associated With Future Federally Mandated Greenhouse Gas**
14 **Reductions**

15 **Q. Have witnesses for OTP and MDU discussed the potential for federal**
16 **regulation of greenhouse gas emissions in the Supplemental testimony filed**
17 **on March 10, 2008?**

18 A. Yes. OTP witness Uggerud, MDU witness Stomberg and OTP/MDU witness
19 Grieg all discuss the potential for federal regulation of CO₂ emissions in the
20 testimony they filed on March 10, 2008.⁷⁵

21 **Q. What mandatory greenhouse gas emissions reductions programs are**
22 **currently under review in the U.S. federal government?**

23 A. To date, the U.S. government has not required greenhouse gas emission
24 reductions. However, an increasing number of legislative initiatives for
25 mandatory emissions reduction proposals have been introduced in Congress.

⁷⁴ Applicants' Exhibit 116 in the Minnesota PUC CON Dockets, at page 6, lines 3-4.

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1 These proposals establish carbon dioxide emission trajectories below the
2 projected business-as-usual emission trajectories, and they generally rely on
3 market-based mechanisms (such as cap and trade programs) for achieving the
4 targets. The proposals also include various provisions to spur technology
5 innovation, as well as details pertaining to offsets, allowance allocation,
6 restrictions on allowance prices and other issues. The federal proposals that
7 would require greenhouse gas emission reductions that had been submitted in the
8 current U.S. Congress are summarized in Table 1 below.

⁷⁵ See OTP Exhibit 112, at page 17, lines 6-17, MDU Exhibit 213, at page 6, line 19, to page 7, line 7, OTP/MDU Exhibit 326, at page 3, lines 1-20, and OTP/MDU Exhibit 327.

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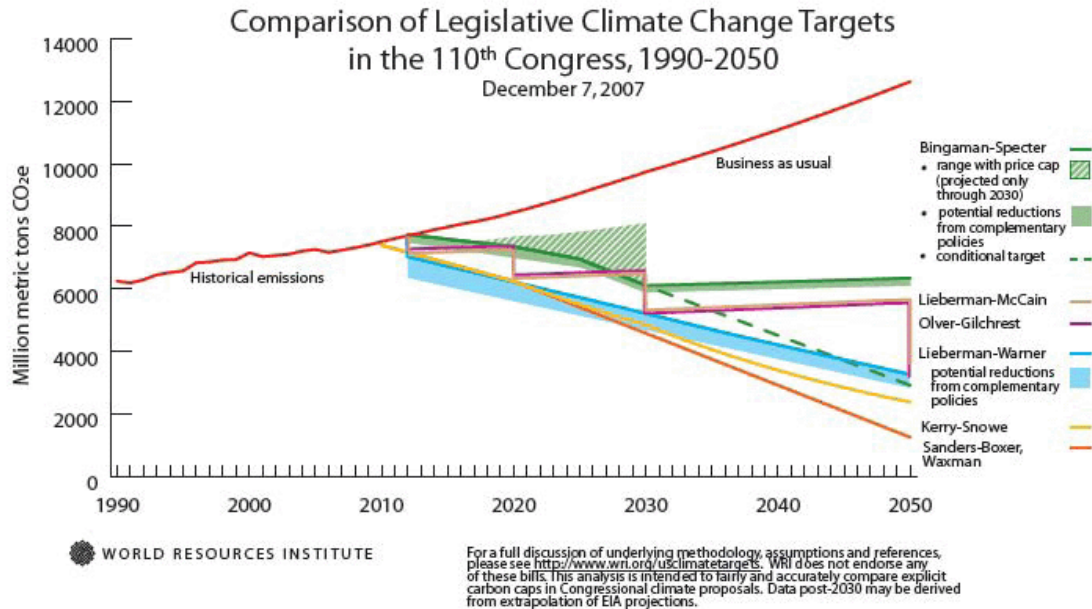
Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in the current U.S. Congress

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
Feinstein- Carper .317	Electric Utility Cap & Trade Act	2007	2006 level by 2011, 2001 level by 2015, 1%/year reduction from 2016-2019, 1.5%/year reduction starting in 2020	Electricity sector
Kerry-Snowe S.485	Global Warming Reduction Act	2007	2010 level from 2010-2019, 1990 level from 2020-2029, 2.5%/year reductions from 2020-2029, 3.5%/year reduction from 2030-2050, 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	2004 level in 2012, 1990 level in 2020, 20% below 1990 level in 2030, 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	2%/year reduction from 2010 to 2020, 1990 level in 2020, 27% below 1990 level in 2030, 53% below 1990 level in 2040, 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	Cap at 2006 level by 2012, 1%/year reduction from 2013-2020, 3%/year reduction from 2021-2030, 5%/year reduction from 2031-2050, equivalent to 70% below 1990 level by 2050	US national
Bingaman-Specter S.1766	Low Carbon Economy Act	2007	2012 levels in 2012, 2006 levels in 2020, 1990 levels by 2030. President may set further goals ≥60% below 2006 levels by 2050 contingent upon international effort	Economy-wide
Lieberman-Warner S. 2191	America's Climate Security Act	2007	2005 level in 2012, 1990 level in 2020, 65% below 1990 level in 2050	U.S. electric power, transportation, and manufacturing sources.

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The emissions levels that would be mandated by the bills that have been introduced in the current Congress are shown in Figure 3 below:

1 **Figure 3: Emissions Reductions Required under Climate Change Bills in**
 2 **Current US Congress**



3
 4 The ultimate goals of these bills generally reflect the 60% to 80% range of
 5 emission reductions from current levels that leading scientists now believe will be
 6 necessary to stabilize atmospheric CO₂ concentrations by the middle of this
 7 century.

8 **Q. Are individual states also taking actions to reduce greenhouse gas emissions?**

9 A. Yes. A number of states are taking significant actions to reduce greenhouse gas
 10 emissions, both individually and as part of regional efforts.

11 For example, Table 2 below lists the emission reduction goals that have been
 12 adopted by states in the U.S. Regional action also has been taken in the
 13 Northeast, Midwest and Western regions of the nation.

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Table 2: Announced State and Regional Greenhouse Gas Emission Reduction Goals

State	GHG Reduction Goal	Western Climate Initiative member (15% below 2005 levels by 2020)	Regional Greenhouse Gas Initiative member (Cap at current levels 2009-2015, reduce this by 10% by 2019)
Arizona	2000 levels by 2020 50% below 2000 levels by 2040	yes	
California	2000 levels by 2010 1990 levels by 2020 80% below 1990 levels by 2050	yes	
Connecticut	1990 levels by 2010 10% below 1990 levels by 2020 75-85% below 2001 levels in the long term		yes
Delaware			yes
Florida	2000 levels by 2017 1990 levels by 2025 80% below 1990 levels by 2050		
Hawaii	1990 levels by 2020		
Illinois	1990 levels by 2020 60% below 1990 levels by 2050		
Maine	1990 levels by 2010 10% below 1990 levels by 2020 75-80% below 2003 levels in the long term		yes
Maryland			yes
Massachusetts	1990 levels by 2010 10% below 1990 levels by 2020 75-85% below 1990 levels in the long term		yes
Minnesota	15% by 2015, 30% by 2025 80% by 2050		
New Hampshire	1990 levels by 2010 10% below 1990 levels by 2020 75-85% below 2001 levels in the long term		yes
New Jersey	1990 levels by 2020 80% below 2006 levels by 2050		yes
New Mexico	2000 levels by 2012 10% below 2000 levels by 2020 75% below 2000 levels by 2050	yes	
New York	5% below 1990 levels by 2010 10% below 1990 levels by 2020		yes
Oregon	Stabilize by 2010 10% below 1990 levels by 2020 75% below 1990 levels by 2050	yes	
Rhode Island	1990 levels by 2010 10% below 1990 levels by 2020 75-80% below 2001 levels in the long term		yes
Utah		yes	
Vermont	1990 levels by 2010 10% below 1990 levels by 2020 75-85% below 2001 levels in the long term		yes
Washington	1990 levels by 2020 25% below 1990 levels by 2035 50% below 1990 levels by 2050	yes	

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New regional efforts to reduce greenhouse gas emissions also have been undertaken in the Midwest since I filed testimony in May, 2007. For example, in November 2007, the Governors of six Midwestern states, including Minnesota, Illinois, Iowa, Kansas, Michigan and Wisconsin, and the Premier of Manitoba

1 signed the Midwestern Greenhouse Gas Accord. This agreement committed the
2 states to establishing greenhouse gas emissions targets and timetables, to
3 developing a market based and multi-sector cap-and-trade mechanism to achieve
4 those reduction targets, to developing a regional registry and tracking mechanism,
5 and to developing and implementing additional steps as needed to achieve the
6 reduction targets.⁷⁶ The Governors of Indiana, Ohio and South Dakota also signed
7 the agreement as observers to participate in the formation of a regional cap-and-
8 trade system.

9 **Q. What CO₂ prices have OTP and MDU used in the supplemental modeling**
10 **analyses of the Big Stone II Project that they have presented in this**
11 **proceeding?**

12 A. OTP and MDU did not use any CO₂ prices in the new analyses presented in their
13 Supplemental testimony filed in this proceeding on March 10, 2008.

14 **Q. Did OTP and/or MDU use any CO₂ prices in the new modeling analyses they**
15 **presented to the Minnesota Public Utilities last fall in the CON Dockets?**

16 A. OTP used a nominal \$9/ton CO₂ price in the new modeling analyses it filed with
17 the Minnesota PUC in the CON Dockets last November. This means that the
18 company assumed that the prices of CO₂ emissions allowances would not increase
19 over time, even with inflation. To the contrary, OTP assumed that the real prices
20 of CO₂ emissions allowances will decrease over time.

21 MDU did not use any CO₂ price in its modeling analyses in the Minnesota CON
22 Dockets.

⁷⁶ <http://www.midwesterngovernors.org/resolutions/GHGAccord.pdf>.

1 **Q. Does the fact that MDU does not include any CO₂ prices in its Big Stone II**
2 **modeling analyses mean that the company will not have to pay any CO₂ costs**
3 **when the federal government implements a carbon tax or a cap-and-trade**
4 **regulatory regime for greenhouse gases?**

5 A. No. Merely assuming that CO₂ prices will be zero, as MDU does in its modeling
6 analyses, does not mean that the Company will be able to avoid paying for CO₂
7 emissions allowances under a cap-and-trade system or a carbon tax. All it means
8 is that what the Company may call its least cost plan with Big Stone II really isn't
9 a least cost plan because it does not reflect the likelihood of significant CO₂ costs.

10 **Q. Does the investment community consider it important for investor owned**
11 **utilities to consider CO₂ prices in their resource planning?**

12 A. Increasing concern has been expressed in the financial community about the risks
13 associated with new coal-fired power plants. For example, in its January 28, 2008
14 assessment of the *Top 10 U.S. Electric Utility Credit Issues for 2008 and Beyond*,
15 Standard & Poor's noted that "the single biggest challenge regulated electric
16 utilities will tackle is the discharge of carbon dioxide (CO₂) into the air:"

17 Congress took a futile stab at the broader global warming issue in
18 late 2007, but key credit impacting decisions concerning CO₂ went
19 unresolved. Three items that will have the biggest credit impact are
20 integrated resource plans that reduce or eliminate the building of
21 new coal-fired power plants, the need for carbon sequestration on
22 existing coal units to meet newer, more exacting standards, and
23 research and development for cleaner coal technologies. All are
24 potentially large ticket items that electric utilities might have to
25 confront.

26 It is likely that the new administration in Washington will try to
27 make its mark on greenhouse gas sometime in 2009; until then
28 federal action seems remote, although campaign rhetoric will be
29 heated. Framing the 2009 dialogue will be energy independence,
30 national security, and carbon-based fuels, such as coal and oil.
31 Future legislation that crimps coal use and affects credit quality for
32 electric utilities is possible, but not certain at this moment, given
33 past stalemates on energy policy issues. Of course, this inertia is

1 the worst of all outcomes for electric utility managements and
2 those who invest in their fixed-income debt instruments.

3 Funding for reducing greenhouse gas emissions will affect credit
4 quality for coal plant operators. Preserving credit quality may be
5 possible from carefully structured initiatives, such as a cap-and-
6 trade mechanism, incentive returns, or a wires surcharge. A rider
7 on customer bills for CO₂ costs similar to month or quality fuel
8 true-ups would also benefit cash flow and credit.⁷⁷

9 At the same time, in early February 2008 three leading Wall Street financial
10 institutions, Citigroup, JP Morgan Chase and Morgan Stanley, adopted a set of
11 Carbon Principles.⁷⁸ These Principles created an Enhanced Diligence Framework
12 to help lenders better understand and evaluate the potential carbon risks
13 associated with coal plant investments. The three Carbon Principles adopted by
14 these leading institutions are:

- 15 ■ ***Energy Efficiency.*** An effective way to limit CO₂ emissions is to
16 not produce them. The signatory financial institutions will
17 encourage clients to invest in cost-effective demand reduction,
18 taking into consideration the value of avoided CO₂ emissions. We
19 will also encourage regulatory and legislative changes that increase
20 efficiency in electricity consumption including the removal of
21 barriers to investment in cost-effective demand reduction. The
22 institutions will consider demand reduction caused by increased
23 energy efficiency (or other means) as part of the Enhanced
24 Diligence Process and assess its impact on proposed financings of
25 certain fossil fuel generation.

- 26 ■ ***Renewable and low carbon distributed energy technologies,***
27 Renewable energy and low carbon distributed energy technologies
28 hold considerable promise for meeting the electricity needs of the
29 US while also leveraging American technology and creating jobs.
30 We will encourage clients to invest in cost-effective renewables
31 and distributed technologies, taking into consideration the value of
32 avoided CO₂ emissions. We will also encourage legislative and
33 regulatory changes that remove barriers to, and promote such
34 investments (included related investments in infrastructure and
35 equipment needed to support the connection of renewable sources

⁷⁷ Exhibit DAS-S4, at page 2.

⁷⁸ A copy of the Carbon Principles are attached as Exhibit DAS-S5.

1 to the system). We will consider production increases from
2 renewable and low carbon generation as part of the Enhanced
3 Diligence process and assess their impact on proposed financings
4 of certain new fossil fuel generation.

5 ▪ ***Conventional and advanced generation.*** In addition to cost
6 effective energy efficiency, renewables and low carbon distributed
7 generation, investments in conventional or advanced generating
8 facilities will be needed to supply reliable electric power to the US
9 market. This may include power from natural gas, coal and nuclear
10 technologies. Due to evolving climate policy, investing in CO₂-
11 emitting fossil fuel generation entails uncertain financial,
12 regulatory and certain environmental liability risks. It is the
13 purpose of the Enhanced Diligence process to assess and reflect
14 these risks in the financing considerations for certain fossil fuel
15 generation. We will encourage regulatory and legislative changes
16 that facilitate carbon capture and storage (CCS) to further reduce
17 CO₂ emissions from the electric sector.

18 **Q. Do OTP and MDU already have the financing for their proposed**
19 **participation in the Big Stone II Project?**

20 A. I believe that the answer is no. Neither company yet has the financing for its
21 proposed share of the Big Stone II Project.

22 **Q. What was the basis for the \$9/ton CO₂ price used by OTP in its recent**
23 **modeling analyses in the Minnesota PUC CON Dockets?**

24 A. OTP has said that it used a \$9/ton CO₂ price based on a recommendation by the
25 Department of Commerce concerning interim CO₂ prices to be used for resource
26 planning until the Minnesota Commission adopts a final set of required CO₂
27 prices.⁷⁹ It is my understanding that this \$9/ton figure initially came from a 2003
28 settlement reached by Xcel Energy concerning the proposed Comanche power
29 plant in Colorado.

⁷⁹ See, for example, Applicants' Exhibit 116 in Minnesota CON Dockets Nos. CN-05-619 and TR-05-1275, at page 16, lines 13-14.

1 **Q. Was the manner in which OTP applied the \$9/ton CO₂ cost consistent with**
2 **how Xcel Energy has used that price?**

3 A. No. Xcel Energy has escalated the \$9/ton price at the rate of inflation starting in
4 the year 2010. As a result, the price remained constant in 2010 dollars. As I noted
5 above, OTP applied a \$9/ton cost starting in 2013 and did not increase that cost in
6 line with inflation. Consequently, the CO₂ prices that were used in the past by
7 Xcel Energy subsequent to the Comanche Settlement were substantially higher
8 than the CO₂ prices now being used by OTP.

9 **Q. Does Xcel Energy continue to use a \$9/ton CO₂ price, escalated at the rate of**
10 **inflation, in its resource planning?**

11 A. Xcel Energy only uses the \$9/ton CO₂ price in its resource planning as the low
12 end of a wide range of future CO₂ prices. This range includes a mid case CO₂
13 price of \$20/ton starting in 2010 and escalating at 2.5 percent per year and high
14 and low scenarios of \$9/ton and \$40/ton also starting in 2010 and escalating at the
15 rate of inflation.⁸⁰

16 **Q. Is the \$9/ton CO₂ price forecast used by OTP in its recent Big Stone II**
17 **modeling analyses in the Minnesota PUC CON Dockets reasonable in light of**
18 **the uncertainty surrounding future CO₂ costs and the stringent reductions in**
19 **CO₂ emissions that would be required under the global warming bills that**
20 **have been introduced in the current U.S. Congress?**

21 A. No. As Xcel Energy indicates, a \$9/ton CO₂ price may be reasonable as the lower
22 end of a broad range of CO₂ prices being considered in resource planning
23 analyses. But it not reasonable as the highest CO₂ price to use when developing a
24 least cost, least risk resource plan. Given all of the uncertainties surrounding
25 future greenhouse gas regulations and costs, it is prudent to consider a broad

⁸⁰ Northern States Power Company, *2007 Resource Plan*, Docket No. E002/RP-07___, December 14, 2007, at page 4-4.

1 range of CO₂ price forecasts in resource planning, not just a single price trajectory
2 or the narrow range of prices between \$0/ton and \$9/ton.

3 Also, the \$9/ton CO₂ prices assumed by OTP did not provide a significant
4 economic incentive for the development and retrofitting of carbon capture and
5 sequestration technologies on coal plants like Big Stone II because that price
6 would be substantially below the currently estimated costs of carbon capture and
7 sequestration.

8 **Q. How does the \$9/ton CO₂ price used by OTP compare to the expected prices**
9 **of CO₂ emissions allowances under the legislation currently being considered**
10 **in the U.S. Congress?**

11 A. Figure 4 below compares the CO₂ price used by OTP in its recent modeling
12 analyses in the Minnesota CON Dockets to the projected prices of CO₂ emissions
13 allowances developed in recent studies of the prices that would be needed to
14 achieve the emissions reduction targets in global warming legislation that has
15 been introduced in the current Congress. These studies include:

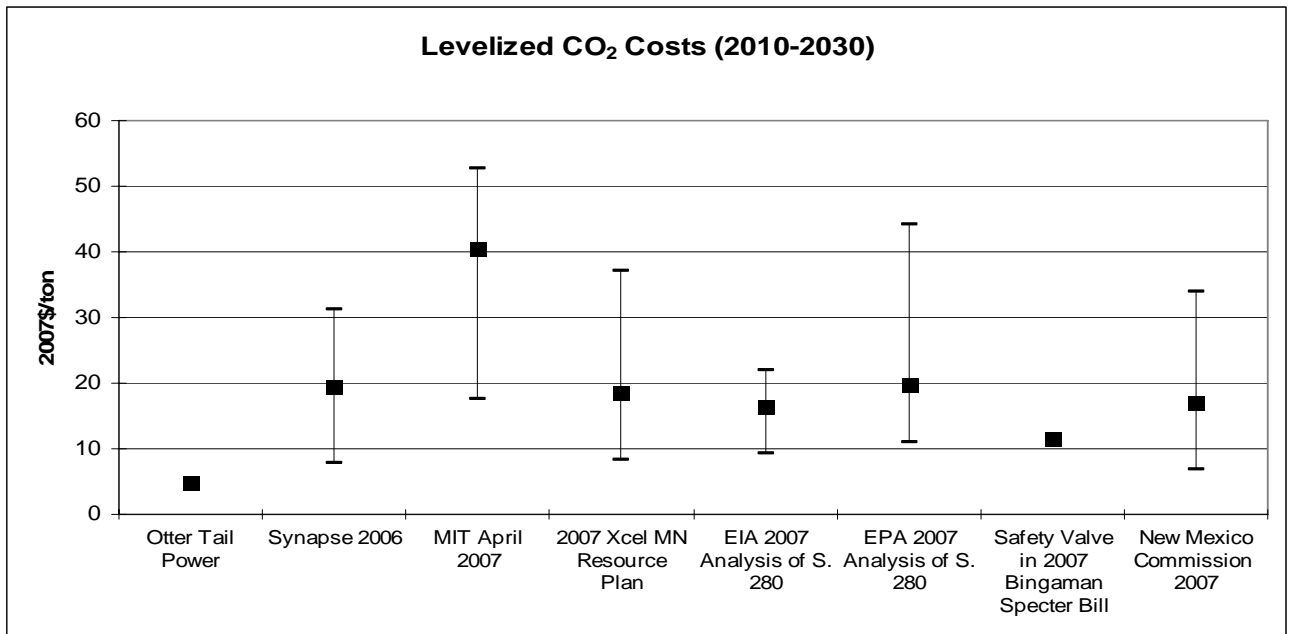
- 16 ■ Analyses of Senate Bill S.280, the current McCain-Lieberman proposal,
17 by the U.S. Environmental Protection Agency (“EPA”) and the Energy
18 Information Administration of the U.S. Department of Energy (“EIA”).⁸¹
19 The EPA examined seven different scenarios reflecting a range of
20 assumptions concerning such important factors as the levels of offsets that
21 would be allowed and the assumed levels of nuclear generation. The EIA
22 examined eight different scenarios. Figure 5 shows the range of leveled
23 costs in the scenarios studied by the EPA and the EIA.
- 24 ■ An Assessment of U.S. Cap-and-Trade Proposals was recently issued by
25 the MIT Joint Program on the Science and Policy of Global Change. This
26 Assessment evaluated the impact of the greenhouse gas regulation bills
27 that are being considered in the current Congress.⁸² The range of CO₂

⁸¹ *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*, Energy Information Administration, July 2007, Supplement to the Energy and Markets Impacts of S. 280, Energy Information Administration, October 2007, and *EPA Analysis of the Climate Stewardship and Innovation Act of 2007, S. 280 in 110th Congress*, July 16, 2007.

⁸² Twenty nine scenarios were modeled in the April 2007 MIT *Assessment of U.S. Cap-and-Trade Proposals*. These scenarios reflected differences in such factors as emission reduction targets (that is, reduce CO₂ emissions 80% from 1990 levels by 2050, reduce CO₂ emissions 50% from 1990

1 costs for the three core scenarios studied by MIT are shown in Figure 5.
 2 These three scenarios analyzed (1) a reduction of greenhouse gas
 3 emissions of 80 percent from current levels by 2050; (2) a reduction of
 4 greenhouse gas emissions of 50 percent from current levels by 2050; and
 5 (3) stabilization of CO₂ emissions at year 2008 levels.
 6 ■ The safety valve prices in Senate Bill S. 1766, the Low Carbon Economy
 7 Act introduced in July 2007 by Senators Bingaman and Specter. The
 8 safety valve price in this proposal starts at \$12/ton in 2012 and escalates at
 9 a real rate of 5 percent per year.

10 **Figure 4: The CO₂ Prices Used by OTP Compared to the Expected**
 11 **Prices Under Legislation in the Current Congress and the**
 12 **Synapse CO₂ Price Forecasts**



13

levels by 2050, or stabilize CO₂ emissions at 2008 levels), whether banking of allowances would be allowed, whether international trading of allowances would be allowed, whether only developed countries or the U.S. would pursue greenhouse gas reductions, whether there would be safety valve prices adopted as part of greenhouse gas regulations, and other factors.

In general, the ranges of the projected CO₂ prices in these scenarios were higher than the range of CO₂ prices in the Synapse forecast. For example, twelve of the 29 scenarios modeled by MIT projected higher CO₂ prices in 2020 than the high Synapse forecast. Fourteen of the 29 scenarios (almost half) projected higher CO₂ prices in 2030 than the high Synapse forecast.

1 Figure 4 also includes the range of CO₂ prices that Xcel Energy has announced
2 that it will use for resource planning⁸³ and the range of CO₂ prices that the New
3 Mexico Public Regulation Commission has directed that utilities use in their
4 electric resource planning. Finally, Figure 4 includes, on a levelized basis, the
5 Synapse forecasts of CO₂ prices that I discussed in my May 31, 2007 Direct
6 Testimony.

7 Thus, on a levelized basis, the CO₂ price used by OTP is lower than even the
8 lower ends of the ranges of CO₂ prices forecast by the EPA, EIA and MIT based
9 on the legislative proposals in the current U.S. Congress and even the safety valve
10 prices in Senate Bill S. 1766, the Bingaman-Specter global warming legislation.
11 The CO₂ price used by OTP also is below the lower ends of the ranges of CO₂
12 prices recently adopted for resource planning by Xcel Energy and the New
13 Mexico Public Regulation Commission.

14 In contrast, the Synapse CO₂ price forecasts are consistent with all of these CO₂
15 prices forecasts.

16 **Q. What CO₂ prices has the Minnesota Public Utilities Commission recently**
17 **adopted for resource planning?**

18 A. The Minnesota Commission has adopted a range of CO₂ prices from \$4/ton to
19 \$30/ton. However, the Commission has not yet issued an Order which indicates
20 the rate of inflation that should be applied to those costs. As a result, I did not
21 include those prices in Figure 4 above. Nevertheless, it is clear that the
22 Commission's range of CO₂ prices would extend significantly above the \$9/ton
23 cost assumed by OTP even if the costs remained flat in nominal terms and did not
24 increase, even just at the rate of inflation.

⁸³ Public Service Company of Colorado, *2007 Colorado Resource Plan*, Volume 2 Technical Appendix, at page 2-30.

1 **Q. Is it credible to assume, as MDU does, that CO₂ costs will be zero, that is,**
2 **there will be no federal regulation of CO₂ emissions at any time during the**
3 **expected 40 to 60 year operating life of the Big Stone II Project?**

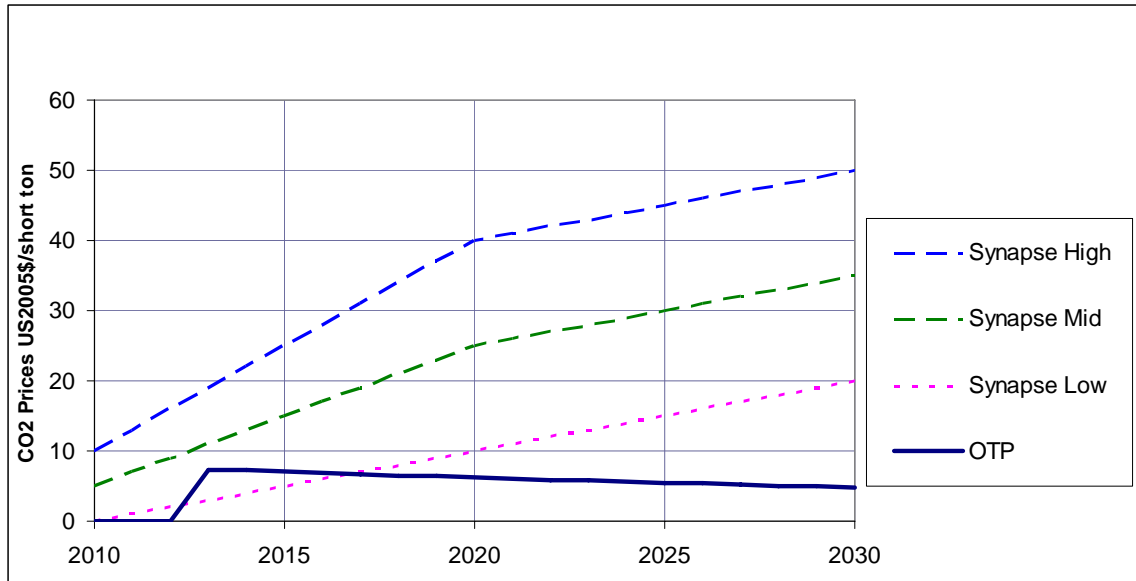
4 A. No. Given the proposals being considered in Congress, public concern and
5 scientific developments, it simply is not credible to project or assume that there
6 will be no federal regulation of greenhouse gas emissions at any time over the
7 next 40 to 60 years or that the Big Stone II Project will be grandfathered or
8 allocated free allowances for all of its CO₂ emissions.

9 **Q. How do the Synapse CO₂ price forecasts compare to the annual CO₂ prices**
10 **used by OTP in its recent modeling analyses in the Minnesota CON Dockets?**

11 A. The annual Synapse CO₂ price forecasts and the CO₂ prices used by OTP, in
12 constant 2005 dollars, are shown in Figure 5 below:

1
2

Figure 5: Synapse and OTP CO₂ Price Forecasts in Constant 2005 Dollars



3

4 **Q. Are the Synapse CO₂ price forecasts shown in Figure 5 based on any**
5 **independent modeling?**

6 A. Yes. Although Synapse did not perform any new modeling to develop our CO₂
7 price forecasts, our CO₂ price forecasts were based on the results of independent
8 modeling prepared at the Massachusetts Institute of Technology (“MIT”), the
9 Energy Information Administration of the Department of Energy (“EIA”), Tellus,
10 and the U.S. Environmental Protection Agency (“EPA”).

11 **Q. What factors will affect the cost of CO₂ emissions allowances?**

12 A. Table 3 below lists a number of factors that will affect projected allowance prices.

1 **Table 3: Factors That Will Affect Emissions Allowance Prices**

Assumption	Increases Prices if...	Decreases Prices if...
"Base case" emissions forecast	Assumes high rates of growth in the absence of a policy, strong and sustained economic growth	Lower forecast of business-as-usual emissions
Complimentary policies	No investments in programs to reduce carbon emissions	Aggressive investments in energy efficiency and renewable energy independent of emissions allowance market
Policy implementation timeline	Delayed and/or sudden program implementation	Early action, phased-in emissions limits
Reduction targets	Aggressive reduction target, requiring high-cost marginal mitigation strategies	Minimal reduction target, within range of least-cost mitigation strategies
Program flexibility	Minimal flexibility, limited use of trading, banking and offsets	High flexibility, broad trading geographically and among emissions types including various GHGs, allowance banking, inclusion of offsets perhaps including international projects
Technological progress	Assume only today's technology at today's costs	Assume rapid improvements in mitigation technology and cost reductions
Emissions co-benefits	Ignore emissions co-benefits	Includes savings in reduced emissions of criteria pollutants

2

3 In particular, Synapse anticipates that technological innovation will temper
 4 allowance prices in the out years of our forecast.

5 **Q. Could carbon capture and sequestration be a technological innovation that**
 6 **might temper or even put a ceiling on CO₂ emissions allowance prices?**

7 A. Yes.

8 **Q. Do OTP and MDU believe that there is currently a commercially viable**
 9 **technology for carbon capture and sequestration from pulverized coal plants**
 10 **like the proposed Big Stone II Project?**

11 A. OTP and MDU provided the following answer when asked whether they believe
 12 that there currently is a commercially viable technology for post-combustion
 13 carbon capture and sequestration for pulverized coal power plants:

1 Currently a number of technologies exist or are in development for
2 post combustion carbon capture. They range from the traditional
3 amine absorber to membrane process to promising chilled
4 ammonia, also to the development of enhanced amine processes.
5 All of these technologies hold some degree of promise and
6 opportunity. Only time will tell which ones will truly become
7 commercially viable technology. By what we would consider
8 today's standards, for the number of units in operation and cost, we
9 would say there is no commercially viable technology in place
10 today, but there are a number of very promising technologies under
11 development, as indicated by the list ... mentioned.⁸⁴

12 **Q. Is this a generally accepted view in the industry?**

13 A. Yes. This conclusion is consistent with the general view in the electric industry.
14 For example, a witness for Dominion Virginia Power presented testimony in July
15 2007 that noted that:

16 carbon capture technology is not commercially viable or available
17 at the present time. Furthermore, the successful integration of all of
18 the technologies needed for a commercial-scale carbon capture and
19 sequestration system has yet even to be demonstrated. As a result,
20 it is not currently feasible to construct a power plant with
21 technology that can capture and store carbon emissions.⁸⁵

22 Even if such technology were available, retrofitting an existing coal plant with the
23 technology for carbon capture and sequestration is expected to be very expensive,
24 increasing the cost of generating power at the plant by perhaps as much as 68 to
25 80 percent or higher.

26 **Q. Have you seen any estimates for the cost of carbon capture and sequestration**
27 **at proposed pulverized coal plants such as the Big Stone II Project?**

28 A. Yes. Hope has been expressed concerning potential technological improvements
29 and learning curve effects that might reduce the estimated cost of carbon capture
30 and sequestration. However, I have seen recent studies by objective sources that

⁸⁴ See the Big Stone II Applicants' Response to Joint Intervenors' Information Request No. 292.a. in the Minnesota PUC CON Dockets.

1 estimate that the cost of carbon capture and sequestration could increase the cost
2 of producing electricity at pulverized coal-fired power plants by 60-80 percent, on
3 a \$/MWh basis.

4 For example, a very recent study by the National Energy Technology Laboratory
5 (“NETL”) has projected that the cost of carbon capture and sequestration would
6 be about \$75/tonne⁸⁶ of CO₂ avoided, in 2007 dollars, for pulverized coal plants.⁸⁷
7 This would translate into about \$65/ton of CO₂ avoided, in 2005 dollars, a cost
8 substantially above even the current Synapse High forecast.

9 The 2007 *Future of Coal Study* from the Massachusetts Institute of Technology
10 estimated that the cost of carbon capture and sequestration would be about
11 \$28/ton although it also acknowledged that there was uncertainty in that figure.⁸⁸
12 The tables in that study also indicated significantly higher costs for carbon capture
13 for new pulverized coal facilities, in the range of about \$37/ton and higher.⁸⁹
14 Transportation and sequestration of the captured CO₂ are expected to add another
15 \$5/ton to \$10/ton to the cost.

16 Moreover, these costs were for new plants that were designed and built to include
17 carbon capture technology at the outset. The MIT *Future of Coal Study* concluded
18 that it would be much more expensive to retrofit carbon capture technology onto
19 existing coal-fired power plants.⁹⁰ That means that the cost of retrofitting carbon
20 capture technology onto plants that would already be built and in operation at the
21 time that the technology becomes proven and commercially viable, like Big Stone
22 II, could be significantly higher than the \$40/ton figure shown in the MIT Study
23 for new coal plants.

⁸⁵ Direct Testimony of Dominion Virginia Power witness James K. Martin in Virginia State
Corporation Commission Case No. PUE-2007-00066, dated July 13, 2007, at page 7, line 11.

⁸⁶ A tonne or metric ton is a measurement of mass equal to 1,000 kilograms or 1.1 tons.

⁸⁷ *Cost and Performance Baseline for Fossil Energy Plants*, National Energy Technology
Laboratory, Revised August 2007, at page 27.

⁸⁸ *The Future of Coal, Options for a Carbon-Constrained World*, Massachusetts Institute of
Technology, 2007, at page xi.

⁸⁹ *Id.*, at page 19.

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1 An October 2007 presentation by Black & Veatch has calculated a cost of
2 \$71/tonne for carbon capture and sequestration. (at page 23). This is about
3 \$64/ton. Black & Veatch is the Applicants' Engineer for the Big Stone II Project.

4 A September 2007 letter from the Edison Electric Institute to Congress on CCS
5 Technology reported:

6 CCS technology will always increase plant construction costs and
7 it has been estimated by the Department of Energy (DOE) and
8 other authorities that CCS will increase the cost of energy from a
9 coal-fired power plant by up to 75 percent or more, depending on
10 the specific circumstances and likely more for smaller facilities or
11 utilities.⁹¹

12 OTP/MDU witness Greig has estimated that the levelized cost of power from a
13 500 MW Big Stone II will be about \$78/MWh for an IOU like OTP and MDU
14 without any carbon costs.⁹² Using the EEI's estimate that adding CCS technology
15 will increase the cost of power from a coal plant by 75 percent, the cost of adding
16 CCS would bring the levelized cost of Big Stone II to approximately \$138/MWh
17 for OTP and MDU.

18 It is important to emphasize that the cost estimates in the NETL, MIT, EEI and
19 Black & Veatch studies are not current costs. These are estimates of what carbon
20 capture and sequestration are likely to cost when installed on new coal-fired
21 power plants. The MIT study, in particular, predicts that it will be even more
22 expensive to retrofit CCS technology onto new pulverized coal plants. If it begins
23 operations in 2013, as currently claimed by OTP and MDU, CCS equipment will
24 have to be retrofitted onto Big Stone II when and if that technology becomes
25 commercially viable.

26 I also have seen some preliminary estimates that some of the new technologies
27 being examined may hold the promise of lowering carbon capture and

⁹⁰ Id., at pages 28-29.

⁹¹ At page 7.

⁹² OTP/MDU Exhibit 326, at page 11, lines 14-20.

1 sequestration costs to perhaps as low as \$20/ton of CO₂ avoided. However, those
2 results are very preliminary and the associated technologies are untested.

3 Even when the technology for CO₂ capture matures, there will always be
4 significant regional variations in the cost of the transportation and storage of the
5 captured CO₂ due to the proximity and quality of storage sites.

6 **Q. Is there any consensus when carbon capture and sequestration technology**
7 **will become commercially viable for pulverized coal plants like the Big Stone**
8 **II Project?**

9 A. No. I have seen estimates that carbon capture and sequestration technology may
10 be proven and commercially viable from as early as 2015 to 2030 or later, if,
11 indeed, it is ever proven to be technically and commercially viable.

12 For example, the 2007 *Future of Coal* study from the Massachusetts Institute of
13 Technology warned that:

14 Many years of development and demonstration will be required to
15 prepare for its successful, large scale adoption in the U.S. and
16 elsewhere. A rushed attempt at CCS [carbon capture and
17 sequestration] implementation in the face of urgent climate
18 concerns could lead to excess cost and heightened local
19 environmental concerns, potentially lead to long delays in
20 implementation of this important option.⁹³

21 **Q. Have OTP and MDU provided any assessments of the potential or the**
22 **feasibility of sequestering the CO₂ from the proposed Big Stone II Project?**

23 A. No. They have instead expressed faith that advances in technology in the future
24 will enable the capture and sequestration of CO₂ emissions from Big Stone II at
25 reasonable costs.⁹⁴

⁹³ *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study, 2007, at page 15.*

⁹⁴ For example, see the Big Stone II Applicants' Response to Joint Intervenors Information Request No. 292.(c), (d) and (e) in the Minnesota PUC CON Dockets.

1 **Q. Have OTP and MDU included any costs associated with carbon capture and**
2 **sequestration in either the estimated Big Stone II Project construction cost or**
3 **in their new modeling analyses?**

4 A. I am not aware of any significant costs for carbon capture and sequestration in the
5 most recent, that is July 2006, Big Stone II Project construction cost estimate.
6 There also is no evidence that OTP and MDU have included any costs associated
7 with carbon capture and sequestration in their recent modeling analyses.

8 **Q. Do you believe that the Synapse CO₂ price forecasts remain valid despite**
9 **being based, in part, on analyses from 2003-2005 which examined legislation**
10 **that was proposed in past Congresses?**

11 A. Yes. Synapse believes it is important for the Minnesota PUC to rely on the most
12 current information available about future CO₂ emission allowance prices, as long
13 as that information is objective and credible. The analyses upon which Synapse
14 relied when we developed our CO₂ price forecasts were the most recent analyses
15 and technical information available when Synapse developed its CO₂ price
16 forecasts in the Spring of 2006. However, new information shows that our CO₂
17 prices remain valid even though the original bills that comprised part of the basis
18 for the forecasts expired at the end of the Congress in which they were
19 introduced.

20 Many of the new greenhouse gas regulation bills that have been introduced in the
21 current Congress would require much steeper reductions in greenhouse gas
22 emissions than would have been required under the bills that had been introduced
23 in Congress at the time we developed our Synapse CO₂ price forecasts. It is
24 reasonable to expect that the increased stringency of current bills will lead to
25 higher CO₂ emission allowance prices. Thus, if anything, our Synapse CO₂ price
26 forecasts may be too low given the increased stringency of the current bills being
27 considered in Congress. The higher forecast natural gas prices that are being
28 forecast today, as compared to the natural gas price forecasts from 2003 or 2004,
29 also can be expected to lead to higher CO₂ emissions allowance prices.

1 **Q. Would it be reasonable to assume that a new pulverized coal-fired plant like**
2 **the Big Stone II Project will be grandfathered under federal climate change**
3 **legislation or will be favored with the provision of extra free CO₂ emission**
4 **allowance allocations that could mitigate or offset the impact of CO₂**
5 **regulations?**

6 A. No. It is unclear what provisions for grandfathering existing coal plants (that is,
7 allocating them allowances for free), if any, will be adopted as part of future
8 greenhouse gas legislation. At the same time, it is unrealistic to expect that many
9 or all of the new coal-fired plants currently being proposed will be grandfathered
10 because of the substantial reductions in CO₂ emissions from current levels that
11 have to be made by 2050 just to stabilize atmospheric concentrations of CO₂ at
12 even 450 ppm to 550 ppm.

13 Meeting these goals will require either a reduction in dependence on coal for
14 electricity generation or a very large investment in conversion of the current coal
15 generating fleet in the U.S. The only realistic way either of these is going to
16 happen is with a large marginal cost on greenhouse gas emissions such as a CO₂
17 tax or higher emissions allowance prices. It is not reasonable to expect that a new
18 pulverized coal plant, like the Big Stone II Project, which will substantially
19 increase the emissions of CO₂ into the atmosphere, will receive significant
20 emission allowances under any U.S. carbon regulation plan.

21 For example, the National Commission on Energy Policy⁹⁵ has recently
22 recommended that “new coal plants built without [carbon capture and
23 sequestration] not be “grandfathered” (i.e., awarded free allowances) in any future
24 regulatory program to limit greenhouse gas emissions.”⁹⁶ A report of an
25 interdisciplinary study at the Massachusetts Institute of Technology on *The*
26 *Future of Coal* similarly noted that:

⁹⁵ The National Commission on Energy Policy is a bipartisan group of 20 energy experts from industry, government, academia, labor, consumer and environmental protection.

1 There is the possibility of a perverse incentive for increased early
2 investment in coal-fired power plants without capture, whether
3 SCPC or IGCC, in the expectation that the emissions from these
4 plants would potentially be “grandfathered” by the grant of free
5 CO₂ allowances as part of future carbon emissions regulations and
6 that (in unregulated markets) they would also benefit from the
7 increase in electricity prices that will accompany a carbon control
8 regime. Congress should act to close this “grandfathering”
9 loophole before it becomes a problem.⁹⁷

10 Additionally, it has been proposed in Congress that new coal-fired plants would
11 be required to actually have carbon capture and sequestration technology. For
12 example, a bill by Massachusetts Senator Kerry would limit CO₂ emissions from
13 new coal-fired facilities to 285 lbs/MWh.⁹⁸ New coal-fired facilities would be
14 defined as those that begin construction on or after April 26, 2007 and would
15 certainly include the proposed Big Stone II Project.

16 **Q. But doesn’t the proposed Lieberman-Warner climate change bill that has**
17 **been forwarded for floor debate in the U.S. Senate allow for the allocation of**
18 **some free CO₂ emissions allowances to new coal-fired power plants?**

19 A. It is true that the proposed Lieberman-Warner legislation, as currently written,
20 would allocate some allowances to new plants. However, there would only be a
21 fixed, and declining over time, pool of allowances for both new and existing
22 plants. Whatever allowances would be allocated to new entrants like Big Stone II
23 would not be available for existing plants.

24 This will be a significant loss to companies like OTP and MDU who already are
25 heavily dependent on coal-fired generation and will likely lead to very significant
26 costs as these companies have to buy allowances to cover generation at their
27 existing facilities. Thus, there may be no net gain of allowances allocated to OTP

⁹⁶ *Energy Policy Recommendations to the President and the 110th Congress*, National Commission
on Energy Policy, April 2007, at page 21.

⁹⁷ *The Future of Coal, Options for a Carbon-Constrained World, an Interdisciplinary MIT Study*,
2007, at page (xiv).

⁹⁸ This would be approximately 15 percent of Big Stone II’s projected emissions of roughly 1 ton per
MWh.

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1 and MDU as allowances that are allocated to Big Stone II might otherwise have
2 been available to these companies for their existing generation.

3 So there is a triple uncertainty – First, will the Lieberman-Warner bill be approved
4 by Congress and signed into law as currently written? Second, how many new
5 plants will there be that will be in the new entrant pool with first access to the
6 limited, and declining, number of emissions allowances that will be available each
7 year? The more new plants in the new entrants pool, the fewer allowances will be
8 available to Big Stone II. Third, how many allowances will OTP and MDU
9 consequently have to buy to cover their existing generation because new plants
10 like Big Stone II received free allowances?

11 As a result, there is no reason to assume that OTP and MDU will receive a
12 significant number of free allowances as a result of their participation in the Big
13 Stone II project that they will not otherwise receive for their existing coal-fired
14 power plants.

15 **Q. Do the new Carbon Principles adopted by Citigroup, JP Morgan Chase and**
16 **Morgan Stanley discuss what is the emerging practice in the financial**
17 **community concerning whether to assume that proposed power plants will**
18 **receive large numbers of free CO₂ emissions allowances?**

19 A. Yes. The Carbon Principles note that the emerging practices in the financial
20 community include “In the absence of clear policy on the regulation of CO₂,
21 financial institutions and clients are starting to use conservative base assumptions,
22 including a mandatory declining cap with full auctioning of allowances.”⁹⁹

⁹⁹ Exhibit DAS-S5.

1 **Q. How much additional CO₂ would the Big Stone II Project emit into the**
 2 **atmosphere?**

3 A. A 500MW Big Stone II would emit approximately 3.7 million tons of CO₂
 4 annually. A 580 MW Big Stone II would emit approximately 4.3 million tons of
 5 CO₂ each year.

6 **Q. What impact would assuming the Synapse range of CO₂ costs have on the**
 7 **total cost of power for OTP and MDU from the Big Stone II Project?**

8 A. The increases in the cost of power from the Big Stone II Project from using the
 9 Synapse range of CO₂ prices, on a levelized basis, are shown in Table 4, below.
 10 The base costs, without CO₂ prices, are taken from the testimony of OTP/MDU
 11 witness Greig. These figures are for a 500 MW sized Big Stone II Project. The
 12 percentage increases would be slightly higher for a 580 MW sized plant.

13 **Table 4: OTP and MDU – Increased Cost of Power from Big Stone II**
 14 **Project Assuming Synapse CO₂ Price Forecasts**

	Big Stone II Project Levelized Cost (2013-2032) (\$/MWh)	Percentage Increase
\$0/ton CO ₂ Price	\$77.65	
Synapse Low CO ₂ Price	\$88.13	13%
Synapse Mid CO ₂ Price	\$101.27	30%
Synapse High CO ₂ Price	\$138.03	47%

15
 16 **6. The New Modeling Analyses Presented by OTP and MDU Do Not**
 17 **Show that the Big Stone II Project is Part of a Least Cost Plan for**
 18 **Either Company**

19 **Q. Have you had a reasonable opportunity to review the new modeling analyses**
 20 **presented by OTP and MDU in this proceeding?**

21 A. No. We have received the workpapers and supporting computer files for these
 22 new analyses within the past week or so. That has not been enough time to
 23 evaluate the analyses fully.

1 **6.A. OTP**

2 **Q. How many modeling analyses does OTP witness Morlock discuss in his**
3 **Supplemental Testimony?**¹⁰⁰

4 A. Mr. Morlock's testimony and conclusions are based on just two runs of the IRP-
5 Manager model. In the first model run, Mr. Morlock used the current cost
6 estimates for the Big Stone II Project. Mr. Morlock then reran the model,
7 reflecting the same set of conditions except for a modest ten percent increase in
8 the capital cost of the Big Stone II Project. Other than that, both runs reflected all
9 of the same assumptions about future costs and alternatives.

10 **Q. Did Mr. Morlock present any other sensitivities in which he reflected CO₂**
11 **costs, higher Big Stone II capital costs, or changes in any other key**
12 **variables?**

13 A. No. Mr. Morlock did not vary any other input assumptions other than the single
14 sensitivity with a modest ten percent increase in the Big Stone II capital cost. He
15 did not examine the impact of CO₂ prices, Big Stone II Project construction costs
16 more than ten percent above the current estimate, additional Project schedule
17 delays, higher or lower fuel prices, higher or lower loads and energy
18 requirements. He also did not compare the relative costs and benefits of alternate
19 plans with or without the Big Stone II Project.

20 **Q. Your May 31, 2007 Direct Testimony concluded that the evidence presented**
21 **by OTP in support of its claim that its participation in the Big Stone II was**
22 **prudent was unpersuasive for a number of reasons.**¹⁰¹ **Is this still your**
23 **conclusion based upon your review of the new modeling analysis discussed by**
24 **OTP witness Morlock in his Supplemental Direct Testimony?**

25 A. Yes. OTP's evidence in support of its claim that its participation in the Big Stone
26 II Project is prudent remains unpersuasive for the following reasons.

¹⁰⁰ OTP Exhibit 117.

¹⁰¹ At page 53, lines 3-4.

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1 First, Mr. Morlock’s testimony and analysis really only show that the Big Stone II
2 Project is a least-cost resource because it is picked as such by the IRP-Manager
3 model, an out-of-date and severely limited model. Mr. Morlock provides
4 absolutely no information on how much of an economic advantage OTP’s
5 preferred plan with Big Stone II produces over other plans that do not include the
6 Big Stone II Project. Without this information, it is impossible to evaluate the
7 potential economic benefits that might be produced by implementing the
8 Company’s preferred plan against the risks associated with that plan or the
9 benefits and risks of pursuing alternatives to the Big Stone II Project.

10 As I discussed at length in my May 31, 2007 Direct Testimony, OTP has
11 acknowledged that the IRP-Manager model has a number of significant
12 limitations.¹⁰² These limitations render the model inadequate for use in
13 determining whether participation in the Big Stone II Project is prudent, for
14 evaluating whether the Project is the most economic option for the company’s
15 ratepayers, and for assessing the economic benefits of participating in that project
16 against the risks of doing so. In fact, OTP appears to be the only utility in the
17 nation that uses this outdated planning model and it is even in the process of
18 changing to a new planning model. As I concluded last year, the North Dakota
19 Commission should not rely on the results from the IRP-Manager model to find
20 that participating in the Big Stone II Project is prudent.

21 When making such an important and far-reaching decision as whether to find that
22 OTP participation in the proposed Big Stone II Project is prudent, the
23 Commission should not rely on two modeling runs from such an out-of-date and
24 limited model reflecting the very same set of assumptions about the future, with
25 the only difference being a modest ten percent increase in capital cost. Instead, the
26 Commission should require OTP to examine through a significant number of
27 sensitivity analyses whether there are lower cost energy efficiency and renewables

¹⁰² At page 54, line 9, to page 56, line 2.

1 alternatives than Big Stone II using state-of-the-art capacity expansion and
2 resource planning models such as the Strategist model used by MDU.

3 Thus, OTP has not presented any sensitivity analyses in this proceeding to
4 examine the impact of a construction cost increase of more than ten percent, the
5 implementation of federal CO₂ regulations, or changes in such key input
6 assumptions as the Project's in-service date, fuel prices, coal supply disruptions,
7 or the cost of building and operating alternatives. As I have shown in Sections 4
8 and 5 above, there is considerable uncertainty regarding the ultimate capital cost
9 of the Big Stone II Project and future costs associated with CO₂ emissions. The
10 IRP-Manager modeling presented by OTP witness Morlock ignores almost all of
11 this uncertainty and basically assumes that future CO₂ prices will be zero or less
12 and that the final cost of the Big Stone II Project will not be more than ten percent
13 higher than OTP's current cost estimate.

14 All that the modeling analysis discussed by Mr. Morlock shows is that the IRP-
15 Manager model selects the Big Stone II Project as part of a least cost plan if the
16 company's assumptions about plant costs, schedule, CO₂ prices, fuel prices, etc.,
17 are correct. There is no assessment of whether the Project would continue to be
18 part of a least cost plan if any key variables, such as CO₂ costs vary, even in a
19 modest way, from the company's assumed values or if the plant's construction
20 cost increases by more than 10 percent.

21 In his new modeling analysis, Mr. Morlock also makes a number of revised
22 assumptions that increase the costs of the alternatives to the Big Stone II Project.
23 This disadvantages those alternatives in his new analyses. For example, he has
24 increased the cost of transmission for the non-wind alternatives, such as natural
25 gas-fired plants, to \$250/kW. At the same time that he adjusted upwards the costs
26 of alternatives, Mr. Morlock used the currently estimated cost for the Big Stone II
27 Project that includes a [**REDACTED**] due to unspecified savings in the
28 generation portion of the project.

1 Given these biases, it really is no surprise that the IRP-Manager picked the Big
2 Stone II Project in the modeling analysis presented by Mr. Morlock.

3 **Q. Have you rerun the IRP-Manager model to examine alternatives to the Big**
4 **Stone II Project?**

5 A. No. Last year we considered attempting to rerun the IRP-Manager model but
6 decided against doing so because of its limitations, the fact that the model is so
7 slow, and because there is no continuing vendor support. We also concluded that
8 we would not be able modify OTP's IRP-Manager database for use in the
9 Strategist model in the limited time we had available to prepare testimony.

10 **Q. Didn't OTP state last year that it was switching to the Strategist model for**
11 **resource planning?**

12 A. Yes.

13 **Q. Has OTP explained why it has not used the Strategist model to prepare its**
14 **new Big Stone II Project related modeling analyses?**

15 A. Yes. Mr. Morlock has presented a litany of problems that he says delayed the
16 transition to the Strategist model. Now the Company is aiming to use the
17 Strategist model for its 2008 Resource Plan analyses.¹⁰³

18 **Q. Is this reasonable?**

19 A. No. The decision to proceed with the Big Stone II Project is a major financial
20 commitment for the Company and a major risk for its ratepayers. The most up-to-
21 date resource planning model should be used to evaluate the costs and risks of the
22 Big Stone II Project and the various alternatives. Strategist is a far more robust
23 tool for evaluating resource alternatives. In contrast, the IRP-Manager model is an
24 inadequate and out-dated tool for examining the full range of risks posed by the
25 proposed Big Stone II Project.

1 **Q. What is your conclusion regarding OTP recent modeling analyses?**

2 A. OTP has not presented credible evidence that its participation in the Big Stone II
3 Project is prudent in that it provides a lower cost and lower risk option than a
4 portfolio of alternatives that would include energy efficiency, renewable resources
5 and, to the extent necessary, some natural gas-fired capacity.

6 **6.B. MDU**

7 **Q. Have you identified any flaws or biases in the modeling analyses presented in**
8 **the Supplemental Testimony of MDU witness Heidell?**

9 A. Yes. Based on our evaluations in the Minnesota PUC CON Dockets and the
10 limited opportunity we have had in this proceeding, we have identified a number
11 of significant flaws in the modeling analyses presented by MDU witness Heidell:

- 12 ■ MDU failed to evaluate the impact of further increases in the construction
13 cost and further delays in the completion of the Big Stone II Project.
- 14 ■ MDU failed to reflect any CO₂ prices whatsoever, let alone look at a
15 reasonable range of possible CO₂ prices.
- 16 ■ MDU failed to prepare any sensitivities whatsoever for such other key
17 input assumptions as coal and gas prices, Big Stone II's operating
18 performance, or the capital costs of CT and CCGT alternatives to the
19 Project.
- 20 ■ MDU also assumed very high capital costs for the CC and wind
21 alternatives. For example:

22 • [

23
24
25 **REDACTED**

26
27
28
29]

¹⁰³ Applicants' Response to Joint Intervenors' Information Request No. 250 in the Minnesota PUC CON Dockets.

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1 ▪ Mr. Heidell assumes that the wind production tax credit will expire on
2 January 1, 2009. This is contrary to OTP’s assumption regarding the
3 extension of the PTC through 2013 and it heavily biases the analyses
4 against new wind facilities.

5 ▪ Mr. Heidell assumes high natural gas prices.

6 In addition, in MDU’s Strategist modeling in the Minnesota PUC CON Dockets,
7 Mr. Heidell did not allow the model to select a CC after 2013. We have not been
8 able to confirm whether he has imposed such a constraint in the modeling
9 analyses he has presented in this proceeding.

10 **Q. What capital costs did Mr. Heidell assume for the cost of building**
11 **combustion turbine and combined cycle natural gas-fired capacity?**

12 A. Mr. Heidell assumed a price of \$1,795/kW, in 2006 dollars, for new combined
13 cycle capacity. He assumed \$975/kW, also in 2006 dollars, for new combustion
14 turbine capacity.

15 **Q. How do the prices for combustion turbine and combined cycle capacity**
16 **assumed by MDU in its most recent Strategist modeling compare to the**
17 **prices used by the other Big Stone II Applicants?**

18 A. CMMPA has assumed a capital cost of \$1,200/kW for new combined cycle
19 capacity and \$870/kW for new combustion turbine capacity.¹⁰⁴ These are lower
20 than the \$1,795/kW CC capital cost and the \$975/kW CT capital cost assumed by
21 MDU.¹⁰⁵

¹⁰⁴ Applicants’ Exhibit 117-A.

¹⁰⁵ Applicants’ Exhibit 118, Table 1, at page 4.

1 **Q. How do the prices for combustion turbine and combined cycle capacity**
2 **assumed by MDU in Mr. Heidell’s recent Strategist modeling compare to the**
3 **estimated prices provided to the Big Stone II Applicants by Black & Veatch?**

4 A. Black & Veatch presented the following estimated EPC costs of CC and CT
5 capacity to the Big Stone II Co-owners in August 2006 and April 2007.¹⁰⁶ “EPC”
6 means the engineering, procurement and construction costs.

7 [**REDACTED**
8]

9 Even if these EPC capital costs are increased by 20 percent to reflect additional
10 owners’ costs [**REDACTED**
11] These ranges would be substantially below the capital
12 costs used by MDU in its new Strategist modeling analyses.

13 **Q. How do the prices for combustion turbine and combined cycle capacity**
14 **assumed by MDU in its most recent Strategist modeling compare to the**
15 **prices used by other utilities in their resource planning?**

16 A. An article in the October 2007 issue of *Power Engineering* has reported that
17 combined cycle plants can now be built for around \$750 to \$850/kW. Even if an
18 additional 20% is added for owners’ costs, this is approximately \$700/kW less
19 than MDU has assumed in its new Strategist modeling analyses.

20 Xcel Energy has used \$806/kW for the capital cost of new CC capacity and
21 \$560/kW for the cost of new CT capacity in the modeling for its 2007 Colorado
22 Resource Plan.¹⁰⁷ Xcel Energy also added \$70/kW for the cost of related
23 transmission system upgrades/additions. These costs are significantly lower than
24 the costs used by MDU.

¹⁰⁶ See, for example, *Big Stone II Project Perspective, Briefing Book for Owners’ CEOs – Supplemental Materials*, April 2007, at Bates Page Number JCO0013878. Included in Exhibit DAS-S6.

¹⁰⁷ Xcel Energy 2007 Colorado Resource Plan, Volume 2 Technical Appendix, at page 2-262.

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1 Other companies and commissions also have assumed significantly lower capital
2 costs for new CC and CT capacity than MDU. For example, a report for the
3 Maryland Public Service Commission in November 2007 recommended using
4 capital costs of \$670/kW for CT capacity and \$950/kW for CC capacity.¹⁰⁸ In
5 addition, the equipment prices in the Gas Turbine World 2007-2008 GTW
6 Handbook also are significantly lower than the capital costs used by MDU would
7 suggest.

8 **Q. Mr. Heidell presents four scenarios in his Supplemental Testimony in this**
9 **proceeding. Do the capital costs of the Big Stone II project vary in these**
10 **analyses?**

11 A. No. All four scenarios assumed the current Big Stone II capital cost and COD.
12 Consequently, MDU has not presented any scenario which reflects higher Big
13 Stone II construction costs or any further delays in the Project's in-service date.

14 **Q. Does Mr. Heidell reflect any CO₂ costs in any of these four scenarios?**

15 A. No. He assumes a \$0 cost for CO₂ in each of these scenarios.

16 **Q. How then do the scenarios differ?**

17 A. As shown on page 2 of MDU Exhibit 214, the first two scenarios, Scenarios I and
18 II, assumed higher wind capacity factors and an extension of the wind Production
19 Tax Credits through the end of 2012. In his new modeling analyses for this
20 proceeding Mr. Heidell has assumed a lower wind capacity factor in Scenarios III
21 and IV and has advanced the expiration of the wind PTC by four years to January
22 1, 2009. He also has assumed significant higher wind capital costs in Scenarios III
23 and IV. In addition, he has made a number of other changes in Scenarios III and
24 IV that are discussed at pages 15 through 21.

¹⁰⁸ *Analysis of Options for Maryland's Energy Future*, prepared for the Maryland Public Service Commission by Kaye Scholer LLP, Levitan & Associates, Inc., and SEMCAS Consulting Associates, November 30, 2007, at page 82.

1 **Q. Did Mr. Heidell present any of these scenarios in his testimony in the**
2 **Minnesota PUC CON Dockets last fall?**

3 A. Yes. Mr. Heidell presented the first two scenarios, which he now calls Scenarios
4 I and II, in the Minnesota PUC CON Dockets.

5 **Q. Were you able to evaluate the Strategist modeling analyses that Mr. Heidell**
6 **presented in the Minnesota PUC CON Dockets and to rerun the Strategist**
7 **model to correct for the flaws you found?**

8 A. Yes.

9 **Q. What did you observe in the results of the modeling Scenarios that Mr.**
10 **Heidell presented in the Minnesota PUC CON Dockets?**

11 A. We found that in MDU's own base case runs, with both the 500 MW and 580
12 MW sized Projects, Big Stone II was the more expensive option during the
13 nearer-term period through 2026. It was only in the more distant, and
14 consequently the more speculative, future, that the Strategist model presented Big
15 Stone II as a lower cost option, even with all of Mr. Heidell's flaw assumptions.

16 **Q. What were the results when you reran Mr. Heidell's modeling Scenarios to**
17 **reflect more reasonable assumptions?**

18 A. In the Minnesota PUC CON Dockets we ran a number of scenarios to see whether
19 the Strategist model would include any of the Big Stone II Project if we included
20 the Synapse CO₂ price forecasts or if we increased the Project's current estimated
21 cost by a minor amount, that is, ten percent.

22 The amount of Big Stone II Project capacity selected by the Strategist model in
23 each of the scenarios we examined are shown in Table 5 below. The MDU base
24 case results for the 500 MW and 580 MW Big Stone II Projects are included for
25 comparison purposes:

1
2

Table 5: Synapse MDU Modeling Results – MWs of the Big Stone II Project selected by Strategist Model

Scenario	MW of Big Stone II Selected
MDU 500MW Base Case with \$0/ton CO ₂ Price	116
MDU 500MW Base Case + \$9/ton CO ₂ Price Escalated at 2.5% Per year	0
MDU 500MW Base Case + Synapse Low CO ₂ Price	0
MDU 500MW Base Case + 10% Higher BSII Capital Cost	0
MDU 580 MW Base Case with \$0/ton CO ₂ Price	116
MDU 580MW Base Case + 10% Higher BSII Capital Cost	0
MDU 580MW Base Case + Synapse Low CO ₂ Price + Model Allowed to Select Big Stone II in 23 MW Increments	23

3

4

Thus, the Strategist model did not include any capacity from a 500 MW sized Big Stone II Project in its lowest cost plan when we assumed either (1) any CO₂ price of \$9/ton or higher or (2) a 10 percent escalation in the current Big Stone II Project capital cost.

7

8

The Strategist model also did not include any capacity from a 580 MW sized Big Stone II Project when we increased the Project’s capital cost by 10 percent. The model selected only 23 MW of the Big Stone II Project when we reran the Company’s base case with our Synapse Low CO₂ prices and allowed the model to select capacity from the Project in 23 MW increments.

10

11

12

1 **Q. In the scenarios where you increased the capital cost of the Big Stone II**
2 **Project by 10 percent, did you also increase the capital costs of the**
3 **alternatives by a comparable amount?**

4 A. No. As I noted earlier, MDU already had assumed extremely high capital costs for
5 the combined cycle and combustion turbine alternatives. It was not necessary or
6 appropriate to further increase the costs of these alternatives when we increased
7 the cost of the Big Stone II Project. The costs for combined cycle and combustion
8 turbine facilities assumed by MDU already accounted for any escalation above
9 their reasonable values based on current market prices or the Black and Veatch
10 projections.

11 **Q. What alternative capacity did the Strategist model add for MDU in those**
12 **scenarios in which it did not select any of the Big Stone II Project?**

13 A. Essentially the Strategist selected more wind and more CT capacity in place of the
14 Big Stone II Project. The specific alternative capacity selected in our modeling
15 scenarios is shown in Table 6 below.

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1
2

Table 6: Alternative Capacity Selected for MDU by the Strategist Model in Lowest Cost Plans in Synapse Analyses

Year	MDU 500MW Base Case + \$9/ton CO ₂ Price (Escalated)	MDU 500MW Base Case + Synapse Low CO ₂ Price	MDU 500MW Base Case + 10% Higher BSII Capital Cost	MDU 580MW Base Case + 10% Higher BSII Capital Cost	MDU 580MW Base Case + Synapse Low CO ₂ Price + BSII Increments
2007					
2008	DSM	DSM	DSM	DSM	DSM
2009	DSM	DSM	DSM	DSM	DSM
2010	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)
2011	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) CT (87 MW)	Wind (61.2 MW) Xcel Contract (105 MW)
2012	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	Wind (30.6 MW)	CT (43.5 MW) Wind (30.6 MW) Wind (30.6 MW)
2013					BS2 (23.2 MW)
2014					CT (43.5 MW)
2015					
2016					
2017	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	
2018					
2019					
2020					
2021					CT (43.5 MW)
2022					
2023					
2024	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	CT (43.5 MW)	
2025					
2026					

3

4 **Q. Have you been able to evaluate in detail or to rerun the Scenarios III and IV**
 5 **presented by Mr. Heidell in his Supplemental Testimony?**

6 A. No. As noted above, we have found that he continues to rely exclusively on the
 7 current Big Stone II construction cost estimate, does not include any CO₂ costs,
 8 and also does not perform any sensitivity analyses to reflect possible changes in
 9 key input assumptions. Mr. Heidell also includes high capital costs for combined
 10 cycle and combustion turbine natural gas-fired capacity and for new wind

1 resources. He also assumes that the wind Production Tax Credit will expire on
2 January 1, 2009.

3 **Q. Do you have any comment on the testimony by MDU witness Stomberg that**
4 **a substantial direct tax on CO₂ emissions or a high allowance price in a cap-**
5 **and-trade system, would change the results of MDU's modeling?¹⁰⁹**

6 A. The results of our modeling described above show that even a moderate CO₂
7 allowance price or tax would change the results of MDU's modeling and show
8 that Big Stone II is not part of a least cost plan.

9 **Q. Do you have any comment on Ms. Stomberg's claim that any costs attached**
10 **to coal as part of climate change regulation will almost certainly increase the**
11 **cost of natural gas going forward and that would change the results of**
12 **modeling analyses of the Big Stone II Project?¹¹⁰**

13 A. It is possible that natural gas demand could be higher due to CO₂ emission
14 regulations and, as a result, natural gas prices could be expected to be somewhat
15 higher than otherwise would be the case. However, the effect is very complicated
16 and will depend on a number of factors such as how much new natural gas
17 capacity is built as a result of the higher coal-plant operating costs due to the CO₂
18 emission allowance prices, how much additional DSM and renewable alternatives
19 become economic and are added to the U.S. system, the levels and prices of any
20 incremental natural gas imports, and changes in the dispatching of the electric
21 system. Indeed, depending on future circumstances there may be some periods in
22 which the prices of natural gas may be lower as a result of CO₂ regulations. Thus
23 it is very difficult to determine, at this time, the amount by which natural gas
24 prices might be raised due to CO₂ emission regulations.

25 In their most recent analyses that have included CO₂ emissions allowance prices,
26 the Big Stone II Applicants have included relatively low CO₂ prices and relatively

¹⁰⁹ MDU Exhibit 213, at [age 7, lines 1-4.

¹¹⁰ MDU Exhibit 213, at page 7, lines 6-9/

1 high increases in natural gas prices as result of CO₂ regulation. For example, the
2 analyses presented in OTP/MDU Exhibits 26 and 327 use relatively low CO₂
3 emissions allowance prices but increase natural gas prices in every year of the
4 analysis by approximately 17 percent. The analyses of likely future CO₂
5 regulation that have been produced by such objective sources as the U.S. EPA, the
6 Energy Information Administration of the U.S. DOE, and the MIT Joint Program
7 on the Science and Policy of Climate Change within the past few years do not
8 show that large of an impact on natural gas prices in all years even in scenarios
9 which eventually end up with substantially higher CO₂ emissions allowance
10 prices. This is true even in those scenarios which do not assume significant
11 increases in the amounts of generation from new nuclear or biomass facilities.

12 **7. The analysis presented by Applicant Witness Greig Does Not Show**
13 **that Participation in the Big Stone II Project is Prudent**

14 **Q. Your May 31, 2007 Direct Testimony concluded that the Commission should**
15 **not rely on the levelized cost analysis presented by OTP/MDU witness Rolfes**
16 **because that analysis was significantly flawed and biased in favor of the Big**
17 **Stone II Project.¹¹¹ Are the new levelized analyses presented by OTP/MDU**
18 **witness Grieg similarly flawed and biased in favor of the Project?**

19 **A.** Yes. The levelized analyses presented by Mr. Greig in OTP/MDU Exhibits 326
20 and 327 are biased in favor of the Big Stone II Project in the following ways:

- 21 ▪ Mr. Greig does not assume any low cost energy efficiency in his CCGT +
22 Wind alternative. Consequently, Mr. Greig's levelized analysis does not
23 show that the Big Stone II Project is a lower cost option than energy
24 efficiency. Indeed, the addition of low cost energy efficiency would lower
25 the cost of the CCGT + Wind option as compared to Big Stone II.
- 26 ▪ Mr. Greig only considered a very low and narrow range of future CO₂
27 prices, that is, from \$0/ton to \$9/ton. As I have demonstrated in Section 4
28 above, this is significantly below a more reasonable range of CO₂ prices
29 that should be used in resource planning.

¹¹¹ At page 67, lines 21-25.

- 1 ▪ Contrary to the assumptions used by his clients in their modeling analyses,
2 Mr. Greig assumes no capacity credit for wind. He therefore overbuilds
3 the amount of natural gas capacity. This leads him to unreasonably inflate
4 the levelized cost of the CCGT + Wind alternative because it requires
5 building more CCGT capacity.
- 6 ▪ Mr. Greig does not prepare any sensitivity analyses to reflect the risk that
7 the Project’s ultimate cost may be significantly higher than the current
8 cost estimate.
- 9 ▪ Mr. Greig’s scenarios that assume that the wind production tax credit will
10 not be available in 2013 are unrealistic and contrary to the assumptions of
11 his clients in their recent Big Stone II Project modeling.

12 **Q. What wind capacity credits do OTP or MDU assume in their recent modeling**
13 **studies?**

14 A. In the modeling it presented in the Minnesota PUC CON Dockets last November,
15 MDU assumed a [] percent capacity credit for wind.

16 **Q. What impact would assuming a capacity credit for wind have on the results**
17 **of Mr. Greig’s analysis?**

18 A. Assuming a capacity credit for wind would mean that less combined cycle
19 capacity would need to be built in the CCGT + Wind alternative. This should lead
20 to a lower levelized cost.

21 **Q. Have OTP or MDU assumed that the wind Production Tax Credit will**
22 **remain in effect through 2013?**

23 A. Yes. OTP has assumed in its recent modeling that the Federal Production Tax
24 Credit would be renewed for five years through 2013 but then not be available
25 that point. In its recent testimony in the Minnesota PUC CON Dockets, MDU
26 assumed that the wind PTC would not expire until January 1, 2013.

27 **Q. Is it reasonable to assume that the wind Production Tax Credit will be**
28 **available through 2013?**

29 A. I agree that it is reasonable to assume that the wind Production Tax Credit will be
30 renewed through 2013. The prospects for the Credit after that point are uncertain.

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1 However, it has been renewed on a number of occasions and may again be
 2 renewed by the Congress in or before 2013. In any event, I agree with OTP that
 3 the Production Tax Credit will be in effect through at least 2013. For this reason,
 4 Mr. Greig’s scenarios that assume no PTC should be given little or no weight.

5 **Q. Are you aware of any investor owned utilities in the Midwest that have**
 6 **assumed that the wind Production Tax Credit will be available in 2013?**

7 A. Yes. I have not made an exhaustive search but I have seen that Xcel Energy has
 8 assumed that the Production Tax Credit will be extended through 2015 in its
 9 recently filed 2007 Resource Plan filing.¹¹²

10 **Q. Have you recalculated Mr. Greig’s analysis to correct for each of the flaws**
 11 **that you have identified above?**

12 A. No. However, we have recalculated Mr. Greig’s analysis to reflect the set of
 13 Synapse CO₂ price forecasts.

14 **Q. What were the results of your recalculation of Mr. Greig’s levelized analysis**
 15 **using the Synapse CO₂ price forecasts?**

16 A. The results of our recalculation of Mr. Greig’s analysis changing only the
 17 assumed CO₂ prices from the \$0/ton and \$9/ton figures used by Mr. Greig to the
 18 Synapse Low, Mid and High price forecasts are shown in Tables 7, 8, and 9
 19 below.

20 **Table 7: Greig Analysis with Synapse Low CO₂ Price Forecast**

		500 MW	580 MW
	CCGT + Wind	Big Stone II	Big Stone II
	(\$/MWh)	(\$/MWh)	(\$/MWh)
Greig Gas Cost - \$1.00/MMBTU	\$85.53	\$87.72	\$85.36
Greig Gas Cost - \$0.50/MMBTU	\$87.16	\$87.72	\$85.36
Greig Base Gas Cost	\$88.94	\$87.72	\$85.36
Greig Gas Cost + \$0.50/MMBTU	\$91.05	\$87.72	\$85.36
Greig Gas Cost + \$1.00/MMBTU	\$93.46	\$87.72	\$85.36

112 At page 4-4.

1 **Table 8: Greig Analysis with Synapse Mid CO₂ Price Forecast**

	500 MW		580 MW
	CCGT + Wind	Big Stone II	Big Stone II
	(\$/MWh)	(\$/MWh)	(\$/MWh)
Greig Gas Cost - \$1.00/MMBTU	\$88.43	\$103.27	\$101.07
Greig Gas Cost - \$0.50/MMBTU	\$90.37	\$103.27	\$101.07
Greig Base Gas Cost	\$92.77	\$103.27	\$101.07
Greig Gas Cost + \$0.50/MMBTU	\$95.22	\$103.27	\$101.07
Greig Gas Cost + \$1.00/MMBTU	\$97.72	\$103.27	\$101.07

3 **Table 9: Greig Analysis with Synapse High CO₂ Price Forecast**

	500 MW		580 MW
	CCGT + Wind	Big Stone II	Big Stone II
	(\$/MWh)	(\$/MWh)	(\$/MWh)
Greig Gas Cost - \$1.00/MMBTU	\$92.08	\$120.00	\$117.90
Greig Gas Cost - \$0.50/MMBTU	\$94.50	\$120.00	\$117.90
Greig Base Gas Cost	\$97.00	\$120.00	\$117.90
Greig Gas Cost + \$0.50/MMBTU	\$99.50	\$120.00	\$117.90
Greig Gas Cost + \$1.00/MMBTU	\$102.00	\$120.00	\$117.90

5 Thus, changing only the CO₂ prices makes both the 500 MW and the 580 MW
 6 sized Big Stone II Project options significantly more expensive than the CCGT +
 7 Wind alternative in each of the natural gas price scenarios with the Synapse Mid
 8 and High CO₂ price forecasts. With the Synapse Low CO₂ price Forecast, the
 9 CCGT + Wind and 500 MW Big Stone II Project are close in price with low
 10 natural gas prices; the 500 MW Big Stone II Project has a slightly lower levelized
 11 cost with higher natural gas prices. Finally, with the Synapse Low CO₂ price
 12 Forecast, the 580 MW has a lower cost than the CCGT + Wind option except that
 13 the levelized cost of the 580 MW coal and CCGT + Wind alternatives narrows
 14 with lower natural gas prices .

15 **Q. Why have you included the Greig Gas Cost - \$0.50/MMBTU and Greig Gas**
 16 **Cost - \$1.00/MMBTU natural gas prices in your recalculation of Mr. Greig’s**
 17 **levelized analysis?**

18 **A.** I included the two lower natural gas prices in my recalculation of Mr. Greig’s
 19 levelized analysis to reflect the great uncertainty surrounding future natural gas

1 prices. Mr. Greig talks about the uncertainty surrounding natural gas prices, but
2 only examines sensitivities that reflect higher natural gas prices than he assumes
3 in his base case. I have included the two lower natural gas price forecasts to
4 reflect the possibility that natural gas prices will be lower than Mr. Greig now
5 projects in his base case.

6 **Q. What do you think would be the impact of correcting for the other flaws you**
7 **have found in Mr. Greig’s analysis?**

8 A. Assuming some low cost energy efficiency and a reasonable capacity credit for
9 wind, further increases in the cost of the Big Stone II Project almost certainly
10 would improve the relative economics of the CCGT + Wind alternative compared
11 to the Big Stone II Project.

12 **Q. What is your overall conclusion regarding the levelized price analysis**
13 **presented by Applicant witness Greig?**

14 A. The Commission should not rely on Mr. Greig’s levelized price forecast as
15 evidence that participation in the Big Stone II Project is prudent.

16 **Q. Does this complete your testimony?**

17 A. Yes.

18

19

20