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

PUBLIC VERSION

CONFIDENTIAL MATERIAL REMOVED

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1. Introduction

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

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

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

A. I am testifying on behalf of Mark Trechock and Dakota Resource Center ("DRC").

Q. Have you testified previously in this Proceeding?

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

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

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

Q. What is the purpose of your supplemental testimony?

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

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

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

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

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. Increasing numbers of proposed coal-fired power plants have been cancelled, delayed and rejected by state regulatory commissions or boards within the past year because of, or at least in large part due to, the uncertainties and risks regarding future power plant construction costs and the potential for regulation of power plant CO_2 emissions.

2. Developments in the nearly ten months since I last filed testimony in this proceeding confirm the conclusion in my May 31, 2007 testimony that the potential for further increases in construction costs and the potential for future federal restrictions on CO_2 emissions are very significant uncertainties and risks for the Big Stone II Project. However, OTP and MDU have not adequately considered these uncertainties and risks in the new testimony and analyses that they have submitted to the Commission.

3. Soaring power plant construction costs will have a significant impact on the results of properly performed resource planning. Actual and recently estimated power plant capital costs have been strongly affected by the domestic and international competition for design and construction resources, manufacturing capacity and commodities. It would be imprudent to not allow for the possibility that these same factors which have led to the skyrocketing of power plant construction costs in recent years will continue to significantly affect project costs during the design and construction of the proposed Big Stone II Project. However, OTP has prepared only a single economic modeling scenario that considered only a 10 percent further increase in the cost of building the Big Stone II Project.

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

4. Events in the past year also demonstrate that it is even more certain that the federal government at some point in the near future will regulate CO_2 emissions from power plants. Federal regulation is coming and it is reasonable to expect that it will have a very substantial impact on the cost of operating a coal-fired power plant like the proposed Big Stone II Project. It cannot be prudent for OTP and MDU to continue their participation in the Project without fully considering the risk of significant CO_2 prices in their resource planning process.

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

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

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

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

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

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

2. Regional Capacity Needs

Q. Do you have any comments about Applicant witness Uggerud's discussion of regional capacity needs?[1]

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

First, I agree that serious actions need to be taken by the load serving entities, generators, state governments and the Midwest Reliability Organization ("MRO") to address possible capacity deficits. However, those actions need to be consistent with regional and state efforts to reduce CO_2 emissions and to increase the region's dependence on renewable resources. Building the Big Stone II Project, which would emit approximately 3.8 to 4.3 million tons of CO2 each year, would be a major step in the wrong direction at this time. The Commission should not be panicked into granting an Advanced Determination of Prudence for an uneconomic coal-fired power plant by the threat of a "looming generation capacity deficits" as suggested by Mr. Uggerud.[2]

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

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1 OTP Exhibit 112, at pages 2-4.
2 Id, at page 3, lines 5-8.

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

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

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

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

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[3] Minn. Stat. Sec. 216B.241 subd. 1c and Minn. Stat. Sec. 216B.2401.
[4] Minn. Stat. Sec. 216B.1691.

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

Another significant new development is the agreement by nine states in the region, working together through the Midwest Governors Association, to adopt the goal of meeting at least 2 percent of regional annual retail sales of electricity through energy efficiency improvements by 2015, with additional savings in subsequent years, and adopted regional renewable energy goals of 10% by 2015, 20% by 2020, 25% by 2025, and 30% by 2030.[6] All of these changes will affect how much new capacity will be needed and what capacity will be the most economic to add, as well as the potential for ratepayer benefits from off-system sales as coal generated power becomes more expensive in the market.

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

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

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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.

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

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

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

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

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

Q. Mr. Uggerud expresses concern about relying "solely on natural gas, conservation or renewable energy instead" and "over-reliance on natural gas."[8] Are you recommending that OTP and MDU rely "solely" on natural gas, conservation or renewable energy?

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

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

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

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

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

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

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

Figure 1: MRO Capacity Fuel Mix 2006

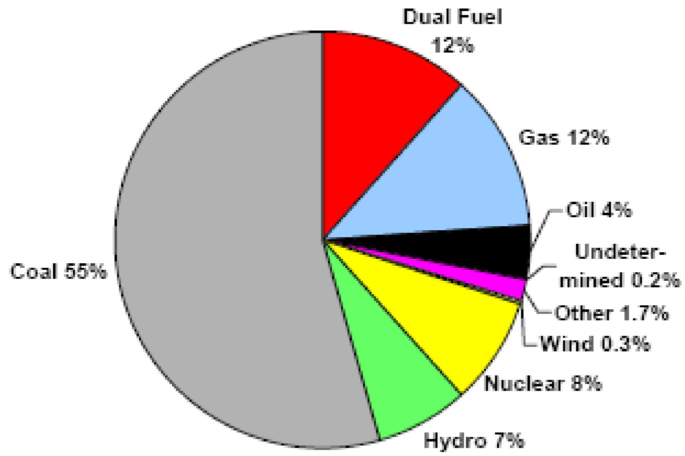
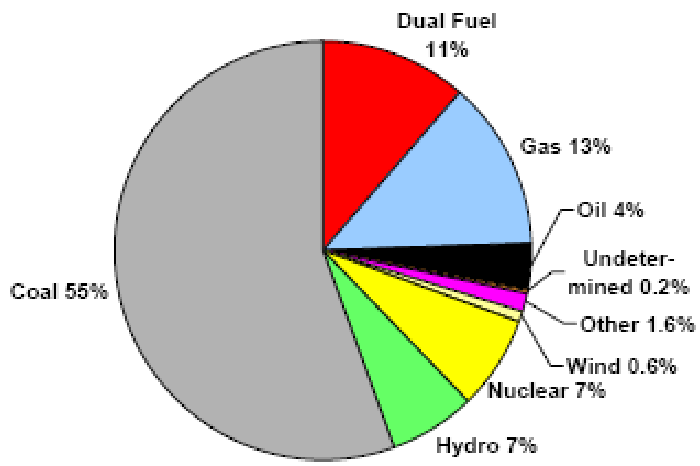


Figure 2: MRO Capacity Fuel Mix 2012



Instead of worrying about having OTP and MDU increase their dependence on natural gas-fired generation, the Commission should be concerned about these companies increasing their dependence on coal-fired generation. For example, MDU witness Stomberg has testified that with Big Stone II, MDU would increase its dependence on coal-fired generation from 77 percent of its installed capacity 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.

of federal regulation of CO_2 emissions, costs trends for coal and rail service from the Powder River Basin.

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

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

A. Yes.

Q. You testified in your May 31, 2007 Direct Testimony that the potential for future restrictions on CO_2 emissions and the potential for large increases in the project's capital cost were significant uncertainties and risks facing the Big Stone II Project. Do these remain significant uncertainties and risks for the Project?

A. Yes. Developments over the past nearly ten months since I submitted my May 31, 2007 testimony in this proceeding confirm and re-emphasize that the potential for future restrictions on CO_2 emissions and the potential for large increases in capital costs are very significant uncertainties and risks associated with building and operating new coal-fired generating plants like the proposed the Big Stone II Project.

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

Q. What consideration have OTP and MDU given in their supplemental testimony to the risks associated future project capital cost increases and the potential for restrictions on future CO_2 emissions?

A. OTP has only given very limited consideration to the potential for future increases in the cost of building the Big Stone II Project. MDU has not given any consideration in its economic modeling analyses to the potential that the cost of building Big Stone II will increase further. Neither company has given any consideration in their modeling analyses in this proceeding to the risks associated with future CO_2 emissions.

Q. Is this a reasonable approach?

A. No. Higher CO_2 prices and increased Project construction costs or additional schedule delays, on their own or in combination, will impact the Project's economics relative to other alternatives and may make the proposed Big Stone II Project uneconomic for of OTP and/or MDU. The important reason to prepare sensitivities is to determine what changes in construction costs and/or CO_2 prices would make the Project uneconomic and then to evaluate how likely those changes are. Unfortunately, OTP and MDU did not prepare these critical analyses. This is imprudent. Risk and uncertainty are inherent in all enterprises. They do not go away merely because they are ignored in economic analyses.

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

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

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

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

> In sum, in light of the now likely regulation of CO_2 emissions in the future due to a broader interest in climate change issues, the increased costs of constructing new coal facilities, and the increased risk of timely permitting to meet planned in-service dates, Public Service does not believe it would be prudent to consider at this time any proposals for new coal plants that do not include CO_2 capture and sequestration.[10]

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

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

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[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.

pulverized coal and IGCC plants but only with proven carbon capture and CO_2 sequestration technologies.[14]

Idaho Power Company similarly has concluded that:

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

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

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

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

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

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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.

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

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

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

> ... coal prices have gone up "dramatically" since Tenaska started planning the project more than a year ago.
>
> And coal plants are largely built with steel, so there's the cost of the unit that we would build has gone up a lot… At one point in our development, we had some of the steel and equipment at some very attractive prices and that equipment all of a sudden was not available.
>
> We went immediately trying to buy additional equipment and the pricing was so high, we looked at the price of the power that would be produced because of those higher prices and equipment and it just wouldn't be a prudent business decision to build it.[18]

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

> The Norborne project costs have significantly increased in less than three years and are now estimated at $2 billion due to worldwide demand for engineering, skilled labor, equipment and materials.
>
> The U.S. Department of Agriculture Rural Utilities Service, a traditional funding source for rural electric cooperatives, is currently unable to finance baseload generation for cooperatives. Although AECI's AA credit rating is one of

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[17] Id.
[18] Available at www.swtimes.com/articles/2007/07/09/news/news02.prt.

> the strongest ratings among all electric utilities nationally, seeking private lending would further increase project costs.
>
> There also is increasing uncertainty in the regulatory environment, and Congress continues to debate the environmental and economic impact of reducing greenhouse gas emissions, making the cost of reducing carbon dioxide from power plants unknown.[19]

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

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

> Furthermore, due to the current uncertainty in the ability to quantify in any meaningful way the cost of compliance with potential federal CO_2 legislation, Bridger 5 as a supercritical unit is no longer a viable option for 2014. Within the last few months, it has become apparent that Congress will enact some restriction upon carbon emissions, but the project cost impact upon new coal generation is currently within such a wide range as to make meaningful risk assessment futile. On November 13, 2007, the National Association of Regulatory Utility Commissioners adopted its first resolution acknowledging that climate change legislation addressing carbon emissions will occur. Within the last few months, most of the planned coal plants in the United States have been cancelled, denied permits, or been involved in protracted litigation. Accordingly, the Company submits that IPP 3, Bridger 5, and the IGCC option at Jim Bridger are no longer viable options for [its] 2012 RFP for the 2012 and 2014 time frame, respectively.
>
> **While the Company is not excluding new coal generation ownership from its 20 year options, absent some change in conditions, it cannot be determined at this time whether new coal generation will satisfy the least cost, least risk standards that would enable us to**

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[19] http://www.aeci.org/NR20080303.aspx.

> **consider it as a viable option within our ten year plans.** (Emphasis added)[20]

- Xcel Energy announced in October 2007 that it was deferring indefinitely its plans to build an IGCC plant in Colorado because the development costs were higher than the utility originally expected.[21]
- TXU cancelled 8 of 11 proposed coal-fired power plants in the spring of 2007 , in large part because of concern over global warming and the potential for federal legislation restricting greenhouse gas emissions.[22]
- Four public power agencies in Florida suspended permitting activities for the coal-fired Taylor Energy Center in the spring of 2007 because of growing concerns about greenhouse gas emissions.[23]
- Tampa Electric cancelled a proposed integrated gasification combined cycle plant ("IGCC") in the fall of 2007 due to uncertainty related to CO_2 regulations, particularly capture and sequestration issues, and the potential for related project cost increases. According to a press release, "Because of the economic risk of these factors to customers and investors, Tampa Electric believes it should not proceed with an IGCC project at this time," although it remains steadfast in its support of IGCC as a critical component of future fuel diversity in Florida and the nation.
- The Orlando Utilities Commission announced in November 2007 that it was cancelling the coal gasification portion of a 285-megawatt integrated gasification combined cycle (IGCC) facility at the Stanton Energy Center. Construction will continue on the natural gas-fired combined cycle generating unit. The Commission cited the impact of possible federal and state regulations related to future emissions restrictions in the state of Florida as the primary reason for terminating construction.[24]
- In June 2007, the Tondu Corp. announced that it was suspending plans to build a planned 600 MW IGCC facility in Texas citing high costs and other concerns related to technology and construction risks.[25]

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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_16asp?n=40.
24 http://www.ouc.com/news/releases/20071114-secb.htm.
25 http://www.reuters.com/article/companyNewsAndPR/idUSN1526955320070615

Q. Have you seen any instance where a participant in a jointly-owned coal-fired power plant project has withdrawn because of concern over increasing construction costs or the potential for future regulation of CO_2 emissions?

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

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

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

The decision of the Florida Public Service Commission in denying approval for the 1,960 MW Glades Power Project was based on concern over the uncertainties over plant costs, coal and natural gas prices, and future environmental costs, 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.

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

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

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

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

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

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[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.

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

A. Yes. The risks associated with building natural gas-fired alternatives include potential CO_2 emissions costs, possible capital cost escalation and fuel price uncertainty and volatility.

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

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

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

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

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

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

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

A. The currently scheduled COD date for Big Stone II is the summer of 2013.[34]

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

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

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REDACTED

[34] Id, at page 1, lines 16-18.

][35]

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

A. Although some work may have been undertaken, it appears that no major design or procurement activities have been completed. As of November 2007 the Big Stone II Co-owners intended **[REDACTED]**[36] Now it appears that Black & Veatch engineering **[REDACTED]**.[37]

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

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

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

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

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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 Intevenors' Information Request No. 243 in Minnesota PUC CON Dockets, at Bates Page Number OTP0008037. Included in Exhibit DAS-S6 (Confidential).

39 Id.

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

A. **[**

REDACTED

][40]

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

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

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

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

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

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

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

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

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[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.

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

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

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

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

A. The worldwide competition is driven mainly by huge demands for power plants in China and India, by a rapidly increasing demand for power plants and power plant pollution control modifications in the United States required to meet SO_2 and NO_x emissions standards, and by the competition for resources from the petroleum refining industry. The demand for labor and resource to rebuild the Gulf Coast area after Hurricanes Katrina and Rita hit in 2005 also has contributed to rising costs for construction labor and materials. The anticipated construction of new nuclear power plants also is expected to compete for limited power plant design and construction resources, manufacturing capacity and commodities.

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

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

> As a result of declining reserve margins in some U.S. regions … brought about by a sustained growth of the economy, the domestic power industry is in the midst of an expansion. Standing in the way are capital costs of new generation that have risen substantially over the past three years. Cost pressures have been caused by demands of global infrastructure expansion. In the domestic power industry, cost pressures have arisen from higher demand for pollution control equipment, expansion of the transmission grid, and new generation. While the industry has experienced buildout cycles in the past, what makes the current environment different is the supply-side resource challenges faced by the construction industry. A confluence of resource limitations have contributed, which Standard & Poors' Rating Services broadly classifies under the following categories
>
> - Global demand for commodities
> - Material and equipment supply
> - Relative inexperience of new labor force, and
> - Contractor availability
>
> The power industry has seen capital costs for new generation climb by more than 50% in the past three years, with more than 70% of this increase resulting from engineering, procurement and construction (EPC) costs. Continuing demand, both domestic and

> international, for EPC services will likely keep costs at elevated levels.[43]

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

Standard & Poor's also concluded that "as capital costs rise, energy efficiency and demand side management already important from a climate change perspective, become even more crucial as any reduction in demand will mean lower requirements for new capacity."[45]

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

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

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

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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.

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

The report further found that:

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

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

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

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

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

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

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

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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.

> contributed to a constantly changing market for commodities and power plant equipment….
>
> * * * *
>
> - Major construction commodities have increased 30% to 80% during the last two years.
> - Labor rate escalation is currently double what it was two years ago.
>
> The global demands (the governments of China and India, for example) for huge expansion in the electricity production sectors will impact equipment prices and creates raw material and fabrication facility (shop space) shortages worldwide for all types of energy production projects. The U.S. electricity production industry announced multiple large projects for development and construction, some of which have supply contracts which have recently been awarded. The energy and process markets are experiencing tremendous growth at the same time.
>
> - Suppliers and Subcontractors that downsized after the market collapsed in 2001 are challenged to grow their capacity and workforce.
> - Continuously increasing costs and longer delivery times for raw materials are influencing engineered equipment costs and commodity purchases.
>
> Increased costs for fuel have caused unexpected increases in fabrication and transportation costs for delivery of fabricated materials, as well as higher construction costs to build this project.[51]

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

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[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.

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[52] Applicants' Confidential Response to Joint Intervenors' Information Request No. 291 in Minnesota PUC CON Dockets, at Bates Page Number JCO0013930. Included in Exhibit DAS-S6 (Confidential).

[53] Id, at Bates Page Number JCO0013931. Included in Exhibit DAS-S6 (Confidential).

[54] Id, at Bates Page Number JCO0013932. Included in Exhibit DAS-S6 (Confidential).

[55] Id, at Bates Page Number JCO0013934. Included in Exhibit DAS-S6 (Confidential).

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

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

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

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

Moreover, there is no evidence that the estimated costs of building the coal-plants listed on this page won't themselves increase significantly as a result of the same 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).

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

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

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

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

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

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

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

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

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

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[59] OTP/MDU Exhibit 324, at page 6, lines 9-11.
[60] Id, at page 6, lines 14-17.

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

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

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

A. Yes.

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

A. Yes. **[**

REDACTED

]. These activities include:

- **[**
- **REDACTED**
- **]**[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).

However, the Memorandum indicated that there are some factors that may influence the achievement of these key dates:

- **[**
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- **REDACTED**
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[62] Id, at Bates Page Numbers OTP0008060 and 8061. Included in Exhibit DAS-S6 (Confidential).

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

A. **[**

REDACTED

[63] **]**.

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

A. Yes. **[** **REDACTED** **]**.

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

A. The notes of the February 14, 2008 Project team meeting indicate that Mr. Rolfes said **[** **REDACTED** **]**[64]

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

A. **[**

REDACTED

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

[65]

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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?

A. No. However, **[**

REDACTED

].[66] For example, in its IRP filed in November 2007 in Colorado, Xcel Energy noted that “Boiler unit costs are reported to have increased 50 to 80% in the last year.”[67]

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?

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.

2006.[68] OTP and MDU have presented no evidence that the forces that caused that major price increase (and that are still causing "staggering" price increases around the nation) will not lead to further cost increases for the Big Stone II Project in the coming years.

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

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

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

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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.

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

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

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

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

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

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

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

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

A. MDU has not presented any sensitivities to this Commission or the Minnesota PUC that have reflected any higher costs for the Big Stone II Project than the currently estimated construction cost. OTP has presented a single scenario in this proceeding that reflects a minor 10 percent increase in the Project's construction cost. However, OTP biases the analysis by failing to include any significant CO_2 prices in its modeling, as I will discuss in the next section of this testimony.

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

A. Yes. However, it is not necessarily reasonable to expect that all of the alternative 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.

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

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

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

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

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

A. Yes. OTP witness Uggerud, MDU witness Stomberg and OTP/MDU witness Grieg all discuss the potential for federal regulation of CO_2 emissions in the testimony they filed on March 10, 2008.[75]

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

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

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

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

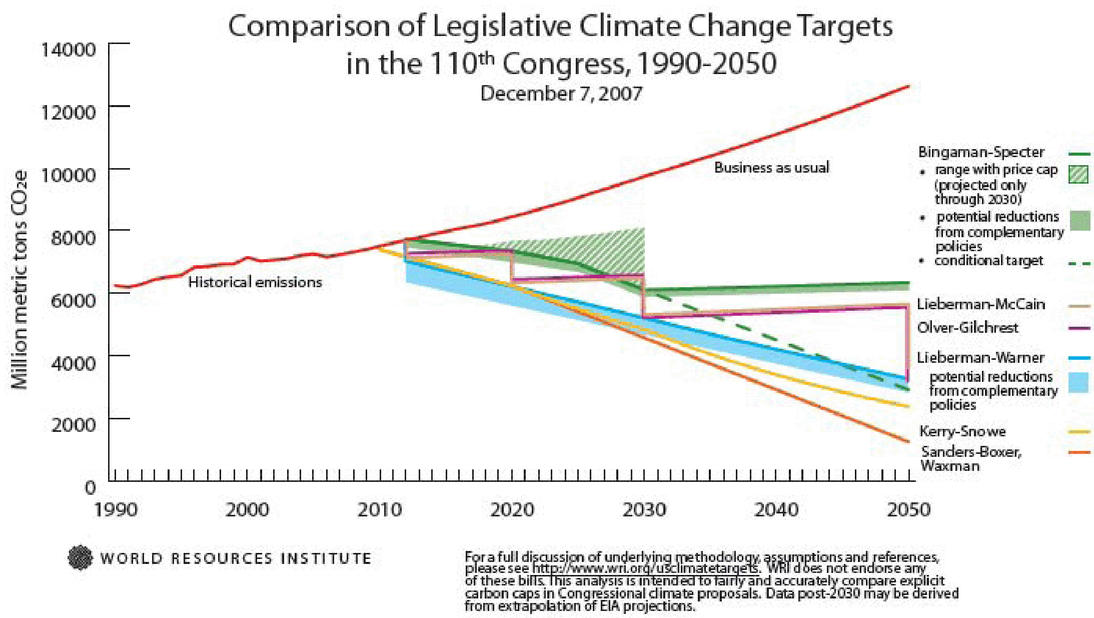
[75] See OTP Exhibit 112, at page 17, lines 6-17, MDU Exhibit 213, at page 6, line 19, to page 7, line 7, OTP/MDU Exhibit 326, at page 3, lines 1-20, and OTP/MDU Exhibit 327.

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.

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

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



The ultimate goals of these bills generally reflect the 60% to 80% range of emission reductions from current levels that leading scientists now believe will be necessary to stabilize atmospheric CO_2 concentrations by the middle of this century.

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

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

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

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	

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

Q. What CO_2 prices have OTP and MDU used in the supplemental modeling analyses of the Big Stone II Project that they have presented in this proceeding?

A. OTP and MDU did not use any CO_2 prices in the new analyses presented in their Supplemental testimony filed in this proceeding on March 10, 2008.

Q. Did OTP and/or MDU use any CO_2 prices in the new modeling analyses they presented to the Minnesota Public Utilities last fall in the CON Dockets?

A. OTP used a nominal $9/ton CO_2 price in the new modeling analyses it filed with the Minnesota PUC in the CON Dockets last November. This means that the company assumed that the prices of CO_2 emissions allowances would not increase over time, even with inflation. To the contrary, OTP assumed that the real prices of CO_2 emissions allowances will decrease over time.

MDU did not use any CO_2 price in its modeling analyses in the Minnesota CON Dockets.

[76] http://www.midwesterngovernors.org/resolutions/GHGAccord.pdf.

Q. Does the fact that MDU does not include any CO_2 prices in its Big Stone II modeling analyses mean that the company will not have to pay any CO_2 costs when the federal government implements a carbon tax or a cap-and-trade regulatory regime for greenhouse gases?

A. No. Merely assuming that CO_2 prices will be zero, as MDU does in its modeling analyses, does not mean that the Company will be able to avoid paying for CO_2 emissions allowances under a cap-and-trade system or a carbon tax. All it means is that what the Company may call its least cost plan with Big Stone II really isn't a least cost plan because it does not reflect the likelihood of significant CO_2 costs.

Q. Does the investment community consider it important for investor owned utilities to consider CO_2 prices in their resource planning?

A. Increasing concern has been expressed in the financial community about the risks associated with new coal-fired power plants. For example, in its January 28, 2008 assessment of the *Top 10 U.S. Electric Utility Credit Issues for 2008 and Beyond,* Standard & Poor's noted that "the single biggest challenge regulated electric utilities will tackle is the discharge of carbon dioxide (CO_2) into the air:"

> Congress took a futile stab at the broader global warming issue in late 2007, but key credit impacting decisions concerning CO2 went unresolved. Three items that will have the biggest credit impact are integrated resource plans that reduce or eliminate the building of new coal-fired power plants, the need for carbon sequestration on existing coal units to meet newer, more exacting standards, and research and development for cleaner coal technologies. All are potentially large ticket items that electric utilities might have to confront.
>
> It is likely that the new administration in Washington will try to make its mark on greenhouse gas sometime in 2009; until then federal action seems remote, although campaign rhetoric will be heated. Framing the 2009 dialogue will be energy independence, national security, and carbon-based fuels, such as coal and oil. Future legislation that crimps coal use and affects credit quality for electric utilities is possible, but not certain at this moment, given past stalemates on energy policy issues. Of course, this inertia is

> the worst of all outcomes for electric utility managements and those who invest in their fixed-income debt instruments.
>
> Funding for reducing greenhouse gas emissions will affect credit quality for coal plant operators. Preserving credit quality may be possible from carefully structured initiatives, such as a cap-and-trade mechanism, incentive returns, or a wires surcharge. A rider on customer bills for CO_2 costs similar to month or quality fuel true-ups would also benefit cash flow and credit.[77]

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

- ***Energy Efficiency***. An effective way to limit CO_2 emissions is to not produce them. The signatory financial institutions will encourage clients to invest in cost-effective demand reduction, taking into consideration the value of avoided CO_2 emissions. We will also encourage regulatory and legislative changes that increase efficiency in electricity consumption including the removal of barriers to investment in cost-effective demand reduction. The institutions will consider demand reduction caused by increased energy efficiency (or other means) as part of the Enhanced Diligence Process and assess its impact on proposed financings of certain fossil fuel generation.

- ***Renewable and low carbon distributed energy technologies***, Renewable energy and low carbon distributed energy technologies hold considerable promise for meeting the electricity needs of the US while also leveraging American technology and creating jobs. We will encourage clients to invest in cost-effective renewables and distributed technologies, taking into consideration the value of avoided CO_2 emissions. We will also encourage legislative and regulatory changes that remove barriers to, and promote such investments (included related investments in infrastructure and equipment needed to support the connection of renewable sources

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77 Exhibit DAS-S4, at page 2.
78 A copy of the Carbon Principles are attached as Exhibit DAS-S5.

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

- ***Conventional and advanced generation***. In addition to cost effective energy efficiency, renewables and low carbon distributed generation, investments in conventional or advanced generating facilities will be needed to supply reliable electric power to the US market. This may include power from natural gas, coal and nuclear technologies. Due to evolving climate policy, investing in CO_2-emitting fossil fuel generation entails uncertain financial, regulatory and certain environmental liability risks. It is the purpose of the Enhanced Diligence process to assess and reflect these risks in the financing considerations for certain fossil fuel generation. We will encourage regulatory and legislative changes that facilitate carbon capture and storage (CCS) to further reduce CO_2 emissions from the electric sector.

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

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

Q. What was the basis for the \$9/ton CO_2 price used by OTP in its recent modeling analyses in the Minnesota PUC CON Dockets?

A. OTP has said that it used a \$9/ton CO_2 price based on a recommendation by the Department of Commerce concerning interim CO_2 prices to be used for resource planning until the Minnesota Commission adopts a final set of required CO_2 prices.[79] It is my understanding that this \$9/ton figure initially came from a 2003 settlement reached by Xcel Energy concerning the proposed Comanche power 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.

Q. Was the manner in which OTP applied the $9/ton CO_2 cost consistent with how Xcel Energy has used that price?

A. No. Xcel Energy has escalated the $9/ton price at the rate of inflation starting in the year 2010. As a result, the price remained constant in 2010 dollars. As I noted above, OTP applied a $9/ton cost starting in 2013 and did not increase that cost in line with inflation. Consequently, the CO_2 prices that were used in the past by Xcel Energy subsequent to the Comanche Settlement were substantially higher than the CO_2 prices now being used by OTP.

Q. Does Xcel Energy continue to use a $9/ton CO_2 price, escalated at the rate of inflation, in its resource planning?

A. Xcel Energy only uses the $9/ton CO_2 price in its resource planning as the low end of a wide range of future CO_2 prices. This range includes a mid case CO_2 price of $20/ton starting in 2010 and escalating at 2.5 percent per year and high and low scenarios of $9/ton and $40/ton also starting in 2010 and escalating at the rate of inflation.[80]

Q. Is the $9/ton CO_2 price forecast used by OTP in its recent Big Stone II modeling analyses in the Minnesota PUC CON Dockets reasonable in light of the uncertainty surrounding future CO_2 costs and the stringent reductions in CO_2 emissions that would be required under the global warming bills that have been introduced in the current U.S. Congress?

A. No. As Xcel Energy indicates, a $9/ton CO_2 price may be reasonable as the lower end of a broad range of CO_2 prices being considered in resource planning analyses. But it not reasonable as the <u>highest</u> CO_2 price to use when developing a least cost, least risk resource plan. Given all of the uncertainties surrounding 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.

range of CO_2 price forecasts in resource planning, not just a single price trajectory or the narrow range of prices between $0/ton and $9/ton.

Also, the $9/ton CO_2 prices assumed by OTP did not provide a significant economic incentive for the development and retrofitting of carbon capture and sequestration technologies on coal plants like Big Stone II because that price would be substantially below the currently estimated costs of carbon capture and sequestration.

Q. How does the $9/ton CO_2 price used by OTP compare to the expected prices of CO_2 emissions allowances under the legislation currently being considered in the U.S. Congress?

A. Figure 4 below compares the CO_2 price used by OTP in its recent modeling analyses in the Minnesota CON Dockets to the projected prices of CO_2 emissions allowances developed in recent studies of the prices that would be needed to achieve the emissions reduction targets in global warming legislation that has been introduced in the current Congress. These studies include:

- Analyses of Senate Bill S.280, the current McCain-Lieberman proposal, by the U.S. Environmental Protection Agency ("EPA") and the Energy Information Administration of the U.S. Department of Energy ("EIA").[81] The EPA examined seven different scenarios reflecting a range of assumptions concerning such important factors as the levels of offsets that would be allowed and the assumed levels of nuclear generation. The EIA examined eight different scenarios. Figure 5 shows the range of levelized costs in the scenarios studied by the EPA and the EIA.
- An Assessment of U.S. Cap-and-Trade Proposals was recently issued by the MIT Joint Program on the Science and Policy of Global Change. This Assessment evaluated the impact of the greenhouse gas regulation bills that are being considered in the current Congress. [82] The range of CO_2

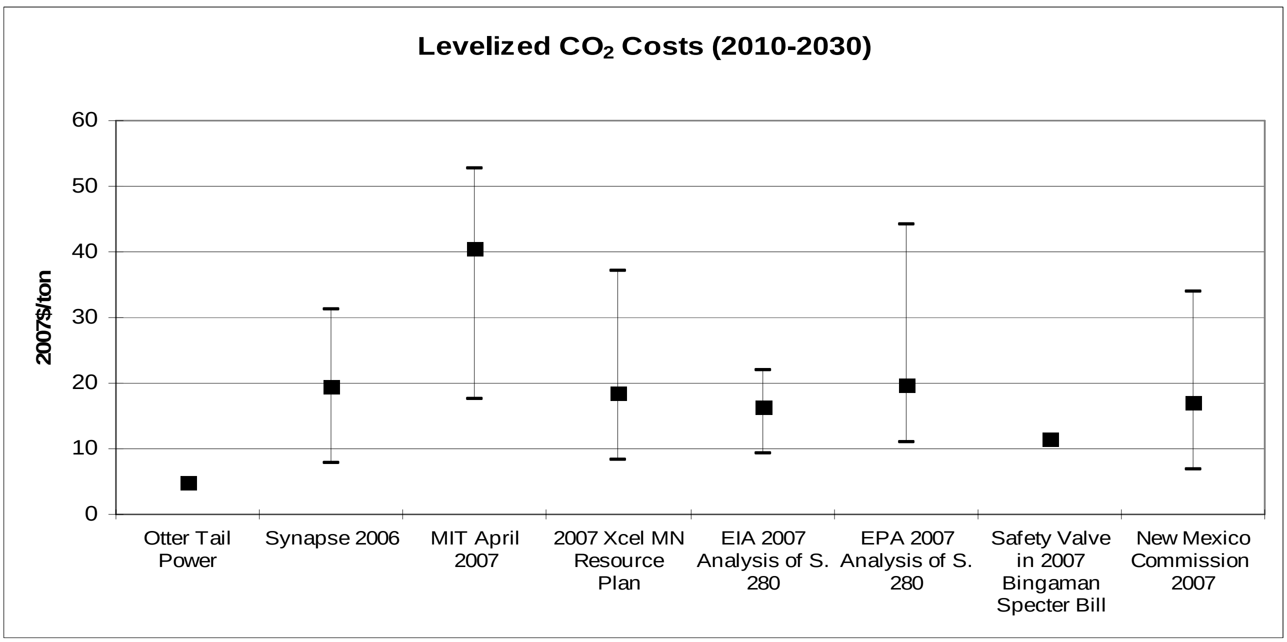
[81] *Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007*, Energy Information Administration, July 2007, Supplement to the Energy and Markets Impacts of S. 280, Energy Information Administration, October 2007, and *EPA Analysis of the Climate Stewardship 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 CO_2 emissions 80% from 1990 levels by 2050, reduce CO_2 emissions 50% from 1990

costs for the three core scenarios studied by MIT are shown in Figure 5. These three scenarios analyzed (1) a reduction of greenhouse gas emissions of 80 percent from current levels by 2050; (2) a reduction of greenhouse gas emissions of 50 percent from current levels by 2050; and (3) stabilization of CO_2 emissions at year 2008 levels.

- The safety valve prices in Senate Bill S. 1766, the Low Carbon Economy Act introduced in July 2007 by Senators Bingaman and Specter. The safety valve price in this proposal starts at $12/ton in 2012 and escalates at a real rate of 5 percent per year.

Figure 4: The CO_2 Prices Used by OTP Compared to the Expected Prices Under Legislation in the Current Congress and the Synapse CO_2 Price Forecasts



levels by 2050, or stabilize CO_2 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 CO_2 prices in these scenarios were higher than the range of CO_2 prices in the Synapse forecast. For example, twelve of the 29 scenarios modeled by MIT projected higher CO_2 prices in 2020 than the high Synapse forecast. Fourteen of the 29 scenarios (almost half) projected higher CO_2 prices in 2030 than the high Synapse forecast.

Figure 4 also includes the range of CO_2 prices that Xcel Energy has announced that it will use for resource planning[83] and the range of CO_2 prices that the New Mexico Public Regulation Commission has directed that utilities use in their electric resource planning. Finally, Figure 4 includes, on a levelized basis, the Synapse forecasts of CO_2 prices that I discussed in my May 31, 2007 Direct Testimony.

Thus, on a levelized basis, the CO_2 price used by OTP is lower than even the lower ends of the ranges of CO_2 prices forecast by the EPA, EIA and MIT based on the legislative proposals in the current U.S. Congress and even the safety valve prices in Senate Bill S. 1766, the Bingaman-Specter global warming legislation. The CO_2 price used by OTP also is below the lower ends of the ranges of CO_2 prices recently adopted for resource planning by Xcel Energy and the New Mexico Public Regulation Commission.

In contrast, the Synapse CO_2 price forecasts are consistent with all of these CO_2 prices forecasts.

Q. What CO_2 prices has the Minnesota Public Utilities Commission recently adopted for resource planning?

A. The Minnesota Commission has adopted a range of CO_2 prices from $4/ton to $30/ton. However, the Commission has not yet issued an Order which indicates the rate of inflation that should be applied to those costs. As a result, I did not include those prices in Figure 4 above. Nevertheless, it is clear that the Commission's range of CO_2 prices would extend significantly above the $9/ton cost assumed by OTP even if the costs remained flat in nominal terms and did not increase, even just at the rate of inflation.

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

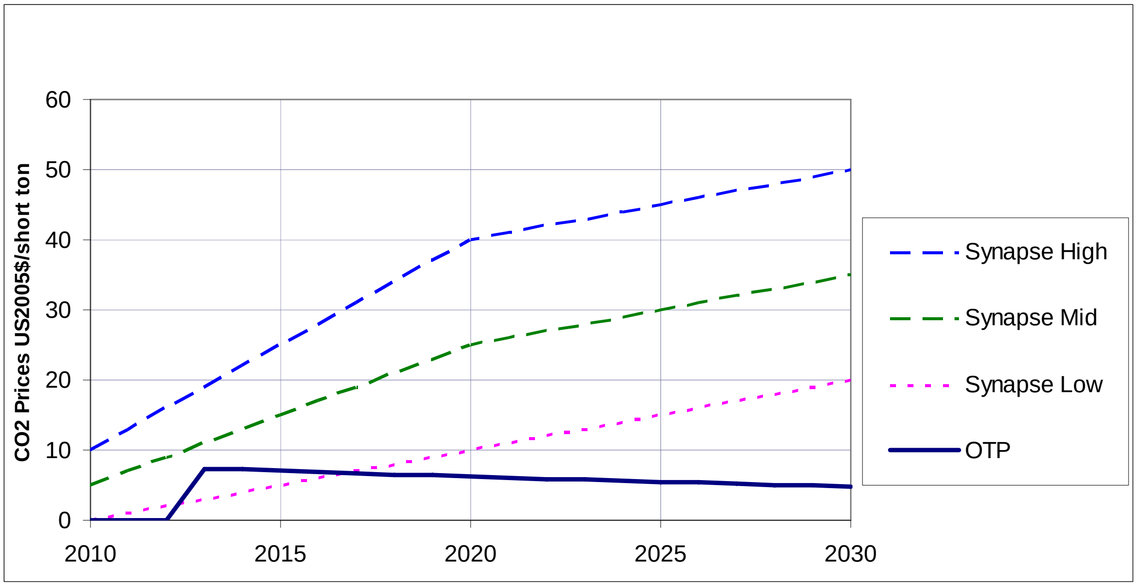
Q. Is it credible to assume, as MDU does, that CO_2 costs will be zero, that is, there will be no federal regulation of CO_2 emissions at any time during the expected 40 to 60 year operating life of the Big Stone II Project?

A. No. Given the proposals being considered in Congress, public concern and scientific developments, it simply is not credible to project or assume that there will be no federal regulation of greenhouse gas emissions at any time over the next 40 to 60 years or that the Big Stone II Project will be grandfathered or allocated free allowances for all of its CO_2 emissions.

Q. How do the Synapse CO_2 price forecasts compare to the annual CO_2 prices used by OTP in its recent modeling analyses in the Minnesota CON Dockets?

A. The annual Synapse CO_2 price forecasts and the CO_2 prices used by OTP, in constant 2005 dollars, are shown in Figure 5 below:

Figure 5: Synapse and OTP CO_2 Price Forecasts in Constant 2005 Dollars



Q. Are the Synapse CO_2 price forecasts shown in Figure 5 based on any independent modeling?

A. Yes. Although Synapse did not perform any new modeling to develop our CO_2 price forecasts, our CO_2 price forecasts were based on the results of independent modeling prepared at the Massachusetts Institute of Technology ("MIT"), the Energy Information Administration of the Department of Energy ("EIA"), Tellus, and the U.S. Environmental Protection Agency ("EPA").

Q. What factors will affect the cost of CO_2 emissions allowances?

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

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

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

Q. Could carbon capture and sequestration be a technological innovation that might temper or even put a ceiling on CO_2 emissions allowance prices?

A. Yes.

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

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

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

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

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

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

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

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

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

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

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

For example, a very recent study by the National Energy Technology Laboratory ("NETL") has projected that the cost of carbon capture and sequestration would be about $75/tonne[86] of CO_2 avoided, in 2007 dollars, for pulverized coal plants.[87] This would translate into about $65/ton of CO_2 avoided, in 2005 dollars, a cost substantially above even the current Synapse High forecast.

The 2007 *Future of Coal Study* from the Massachusetts Institute of Technology estimated that the cost of carbon capture and sequestration would be about $28/ton although it also acknowledged that there was uncertainty in that figure.[88] The tables in that study also indicated significantly higher costs for carbon capture for new pulverized coal facilities, in the range of about $37/ton and higher.[89] Transportation and sequestration of the captured CO_2 are expected to add another $5/ton to $10/ton to the cost.

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

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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.

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

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

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

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

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

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

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90 Id, at pages 28-29.
91 At page 7.
92 OTP/MDU Exhibit 326, at page 11, lines 14-20.

sequestration costs to perhaps as low as $20/ton of CO_2 avoided. However, those results are very preliminary and the associated technologies are untested.

Even when the technology for CO_2 capture matures, there will always be significant regional variations in the cost of the transportation and storage of the captured CO_2 due to the proximity and quality of storage sites.

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

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

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

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

Q. Have OTP and MDU provided any assessments of the potential or the feasibility of sequestering the CO_2 from the proposed Big Stone II Project?

A. No. The have instead expressed faith that advances in technology in the future will enable the capture and sequestration of CO_2 emissions from Big Stone II at reasonable costs.[94]

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[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.

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

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

Q. Do you believe that the Synapse CO_2 price forecasts remain valid despite being based, in part, on analyses from 2003-2005 which examined legislation that was proposed in past Congresses?

A. Yes. Synapse believes it is important for the Minnesota PUC to rely on the most current information available about future CO_2 emission allowance prices, as long as that information is objective and credible. The analyses upon which Synapse relied when we developed our CO_2 price forecasts were the most recent analyses and technical information available when Synapse developed its CO_2 price forecasts in the Spring of 2006. However, new information shows that our CO_2 prices remain valid even though the original bills that comprised part of the basis for the forecasts expired at the end of the Congress in which they were introduced.

Many of the new greenhouse gas regulation bills that have been introduced in the current Congress would require much steeper reductions in greenhouse gas emissions than would have been required under the bills that had been introduced in Congress at the time we developed our Synapse CO_2 price forecasts. It is reasonable to expect that the increased stringency of current bills will lead to higher CO_2 emission allowance prices. Thus, if anything, our Synapse CO_2 price forecasts may be too low given the increased stringency of the current bills being considered in Congress. The higher forecast natural gas prices that are being forecast today, as compared to the natural gas price forecasts from 2003 or 2004, also can be expected to lead to higher CO_2 emissions allowance prices.

Q. Would it be reasonable to assume that a new pulverized coal-fired plant like the Big Stone II Project will be grandfathered under federal climate change legislation or will be favored with the provision of extra free CO_2 emission allowance allocations that could mitigate or offset the impact of CO_2 regulations?

A. No. It is unclear what provisions for grandfathering existing coal plants (that is, allocating them allowances for free), if any, will be adopted as part of future greenhouse gas legislation. At the same time, it is unrealistic to expect that many or all of the new coal-fired plants currently being proposed will be grandfathered because of the substantial reductions in CO_2 emissions from current levels that have to be made by 2050 just to stabilize atmospheric concentrations of CO2 at even 450 ppm to 550 ppm.

Meeting these goals will require either a reduction in dependence on coal for electricity generation or a very large investment in conversion of the current coal generating fleet in the U.S. The only realistic way either of these is going to happen is with a large marginal cost on greenhouse gas emissions such as a CO_2 tax or higher emissions allowance prices. It is not reasonable to expect that a new pulverized coal plant, like the Big Stone II Project, which will substantially increase the emissions of CO_2 into the atmosphere, will receive significant emission allowances under any U.S. carbon regulation plan.

For example, the National Commission on Energy Policy[95] has recently recommended that "new coal plants built without [carbon capture and sequestration] not be "grandfathered" (i.e., awarded free allowances) in any future regulatory program to limit greenhouse gas emissions."[96] A report of an interdisciplinary study at the Massachusetts Institute of Technology on *The Future of Coal* similarly noted that:

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

> There is the possibility of a perverse incentive for increased early investment in coal-fired power plants without capture, whether SCPC or IGCC, in the expectation that the emissions from these plants would potentially be "grandfathered" by the grant of free CO_2 allowances as part of future carbon emissions regulations and that (in unregulated markets) they would also benefit from the increase in electricity prices that will accompany a carbon control regime. Congress should act to close this "grandfathering" loophole before it becomes a problem.[97]

Additionally, it has been proposed in Congress that new coal-fired plants would be required to actually have carbon capture and sequestration technology. For example, a bill by Massachusetts Senator Kerry would limit CO_2 emissions from new coal-fired facilities to 285 lbs/MWh.[98] New coal-fired facilities would be defined as those that begin construction on or after April 26, 2007 and would certainly include the proposed Big Stone II Project.

Q. But doesn't the proposed Lieberman-Warner climate change bill that has been forwarded for floor debate in the U.S. Senate allow for the allocation of some free CO_2 emissions allowances to new coal-fired power plants?

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

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

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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.

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

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

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

Q. Do the new Carbon Principles adopted by Citigroup, JP Morgan Chase and Morgan Stanley discuss what is the emerging practice in the financial community concerning whether to assume that proposed power plants will receive large numbers of free CO_2 emissions allowances?

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

[99] Exhibit DAS-S5.

Q. How much additional CO_2 would the Big Stone II Project emit into the atmosphere?

A. A 500MW Big Stone II would emit approximately 3.7 million tons of CO_2 annually. A 580 MW Big Stone II would emit approximately 4.3 million tons of CO_2 each year.

Q. What impact would assuming the Synapse range of CO_2 costs have on the total cost of power for OTP and MDU from the Big Stone II Project?

A. The increases in the cost of power from the Big Stone II Project from using the Synapse range of CO_2 prices, on a levelized basis, are shown in Table 4, below. The base costs, without CO_2 prices, are taken from the testimony of OTP/MDU witness Greig. These figures are for a 500 MW sized Big Stone II Project. The percentage increases would be slightly higher for a 580 MW sized plant.

Table 4: OTP and MDU – Increased Cost of Power from Big Stone II Project Assuming Synapse CO_2 Price Forecasts

	Big Stone II Project Levelized Cost (2013-2032)	Percentage Increase
	($/MWh)	
$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%

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

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

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

6.A. OTP

Q. How many modeling analyses does OTP witness Morlock discuss in his Supplemental Testimony?[100]

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

Q. Did Mr. Morlock present any other sensitivities in which he reflected CO_2 costs, higher Big Stone II capital costs, or changes in any other key variables?

A. No. Mr. Morlock did not vary any other input assumptions other than the single sensitivity with a modest ten percent increase in the Big Stone II capital cost. He did not examine the impact of CO_2 prices, Big Stone II Project construction costs more than ten percent above the current estimate, additional Project schedule delays, higher or lower fuel prices, higher or lower loads and energy requirements. He also did not compare the relative costs and benefits of alternate plans with or without the Big Stone II Project.

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

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

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[100] OTP Exhibit 117.
[101] At page 53, lines 3-4.

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

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

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

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

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

Thus, OTP has not presented any sensitivity analyses in this proceeding to examine the impact of a construction cost increase of more than ten percent, the implementation of federal CO_2 regulations, or changes in such key input assumptions as the Project's in-service date, fuel prices, coal supply disruptions, or the cost of building and operating alternatives. As I have shown in Sections 4 and 5 above, there is considerable uncertainty regarding the ultimate capital cost of the Big Stone II Project and future costs associated with CO_2 emissions. The IRP-Manager modeling presented by OTP witness Morlock ignores almost all of this uncertainty and basically assumes that future CO_2 prices will be zero or less and that the final cost of the Big Stone II Project will not be more than ten percent higher than OTP's current cost estimate.

All that the modeling analysis discussed by Mr. Morlock shows is that the IRP-Manager model selects the Big Stone II Project as part of a least cost plan if the company's assumptions about plant costs, schedule, CO_2 prices, fuel prices, etc., are correct. There is no assessment of whether the Project would continue to be part of a least cost plan if any key variables, such as CO_2 costs vary, even in a modest way, from the company's assumed values or if the plant's construction cost increases by more than 10 percent.

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

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

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

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

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

A. Yes.

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

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

Q. Is this reasonable?

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

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

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

6.B. MDU

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

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

- MDU failed to evaluate the impact of further increases in the construction cost and further delays in the completion of the Big Stone II Project.
- MDU failed to reflect any CO_2 prices whatsoever, let alone look at a reasonable range of possible CO_2 prices.
- MDU failed to prepare any sensitivities whatsoever for such other key input assumptions as coal and gas prices, Big Stone II's operating performance, or the capital costs of CT and CCGT alternatives to the Project.
- MDU also assumed very high capital costs for the CC and wind alternatives. For example:
  - **[**

REDACTED

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

- Mr. Heidell assumes that the wind production tax credit will expire on January 1, 2009. This is contrary to OTP's assumption regarding the extension of the PTC through 2013 and it heavily biases the analyses against new wind facilities.
- Mr. Heidell assumes high natural gas prices.

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

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

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

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

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

[104] Applicants' Exhibit 117-A.
[105] Applicants' Exhibit 118, Table 1, at page 4.

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

A. Black & Veatch presented the following estimated EPC costs of CC and CT capacity to the Big Stone II Co-owners in August 2006 and April 2007.[106] "EPC" means the engineering, procurement and construction costs.

[REDACTED]

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

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

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

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

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[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.

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

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

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

Q. Does Mr. Heidell reflect any CO_2 costs in any of these four scenarios?

A. No. He assumes a $0 cost for CO_2 in each of these scenarios.

Q. How then do the scenarios differ?

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

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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.

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

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

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

A. Yes.

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

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

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

A. In the Minnesota PUC CON Dockets we ran a number of scenarios to see whether the Strategist model would include any of the Big Stone II Project if we included the Synapse CO_2 price forecasts or if we increased the Project's current estimated cost by a minor amount, that is, ten percent.

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

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

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 CO_2 price of $9/ton or higher or (2) a 10 percent escalation in the current Big Stone II Project capital cost.

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 CO_2 prices and allowed the model to select capacity from the Project in 23 MW increments.

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

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

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

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

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					

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

A. No. As noted above, we have found that he continues to rely exclusively on the current Big Stone II construction cost estimate, does not include any CO_2 costs, and also does not perform any sensitivity analyses to reflect possible changes in key input assumptions. Mr. Heidell also includes high capital costs for combined cycle and combustion turbine natural gas-fired capacity and for new wind resources. He also assumes that the wind Production Tax Credit will expire on January 1, 2009.

Q. Do you have any comment on the testimony by MDU witness Stomberg that a substantial direct tax on CO_2 emissions or a high allowance price in a cap-and-trade system, would change the results of MDU's modeling?[109]

A. The results of our modeling described above show that even a moderate CO_2 allowance price or tax would change the results of MDU's modeling and show that Big Stone II is not part of a least cost plan.

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

A. It is possible that natural gas demand could be higher due to CO_2 emission regulations and, as a result, natural gas prices could be expected to be somewhat higher than otherwise would be the case. However, the effect is very complicated and will depend on a number of factors such as how much new natural gas capacity is built as a result of the higher coal-plant operating costs due to the CO_2 emission allowance prices, how much additional DSM and renewable alternatives become economic and are added to the U.S. system, the levels and prices of any incremental natural gas imports, and changes in the dispatching of the electric system. Indeed, depending on future circumstances there may be some periods in which the prices of natural gas may be lower as a result of CO_2 regulations. Thus it is very difficult to determine, at this time, the amount by which natural gas prices might be raised due to CO_2 emission regulations.

In their most recent analyses that have included CO_2 emissions allowance prices, the Big Stone II Applicants have included relatively low CO_2 prices and relatively

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[109] MDU Exhibit 213, at [age 7, lines 1-4.
[110] MDU Exhibit 213, at page 7, lines 6-9/

high increases in natural gas prices as result of CO_2 regulation. For example, the analyses presented in OTP/MDU Exhibits 26 and 327 use relatively low CO_2 emissions allowance prices but increase natural gas prices in every year of the analysis by approximately 17 percent. The analyses of likely future CO_2 regulation that have been produced by such objective sources as the U.S. EPA, the Energy Information Administration of the U.S. DOE, and the MIT Joint Program on the Science and Policy of Climate Change within the past few years do not show that large of an impact on natural gas prices in all years even in scenarios which eventually end up with substantially higher CO_2 emissions allowance prices. This is true even in those scenarios which do not assume significant increases in the amounts of generation from new nuclear or biomass facilities.

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

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

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

- Mr. Greig does not assume any low cost energy efficiency in his CCGT + Wind alternative. Consequently, Mr. Greig's levelized analysis does not show that the Big Stone II Project is a lower cost option than energy efficiency. Indeed, the addition of low cost energy efficiency would lower the cost of the CCGT + Wind option as compared to Big Stone II.
- Mr. Greig only considered a very low and narrow range of future CO_2 prices, that is, from \$0/ton to \$9/ton. As I have demonstrated in Section 4 above, this is significantly below a more reasonable range of CO_2 prices that should be used in resource planning.

[111] At page 67, lines 21-25.

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

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

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

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

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

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

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

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

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

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

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

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

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

A. No. However, we have recalculated Mr. Greig's analysis to reflect the set of Synapse CO_2 price forecasts.

Q. What were the results of your recalculation of Mr. Greig's levelized analysis using the Synapse CO_2 price forecasts?

A. The results of our recalculation of Mr. Greig's analysis changing only the assumed CO_2 prices from the \$0/ton and \$9/ton figures used by Mr. Greig to the Synapse Low, Mid and High price forecasts are shown in Tables 7, 8, and 9 below.

Table 7: Greig Analysis with Synapse Low CO_2 Price Forecast

	CCGT + Wind	500 MW Big Stone II	580 MW 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

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Table 8: Greig Analysis with Synapse Mid CO_2 Price Forecast

	CCGT + Wind	500 MW Big Stone II	580 MW 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

Table 9: Greig Analysis with Synapse High CO_2 Price Forecast

	CCGT + Wind	500 MW Big Stone II	580 MW 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

Thus, changing only the CO_2 prices makes both the 500 MW and the 580 MW sized Big Stone II Project options significantly more expensive than the CCGT + Wind alternative in each of the natural gas price scenarios with the Synapse Mid and High CO_2 price forecasts. With the Synapse Low CO_2 price Forecast, the CCGT + Wind and 500 MW Big Stone II Project are close in price with low natural gas prices; the 500 MW Big Stone II Project has a slightly lower levelized cost with higher natural gas prices. Finally, with the Synapse Low CO_2 price Forecast, the 580 MW has a lower cost than the CCGT + Wind option except that the levelized cost of the 580 MW coal and CCGT + Wind alternatives narrows with lower natural gas prices .

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

A. I included the two lower natural gas prices in my recalculation of Mr. Greig's levelized analysis to reflect the great uncertainty surrounding future natural gas prices. Mr. Greig talks about the uncertainty surrounding natural gas prices, but only examines sensitivities that reflect higher natural gas prices than he assumes in his base case. I have included the two lower natural gas price forecasts to reflect the possibility that natural gas prices will be lower than Mr. Greig now projects in his base case.

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

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

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

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

Q. Does this complete your testimony?

A. Yes.