SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

CASE NO. EL05-022

IN THE MATTER OF THE APPLICATION BY OTTER TAIL POWER COMPANY

ON BEHALF OF THE BIG STONE II CO-OWNERS

FOR AN ENERGY CONVERSION FACILITY SITING PERMIT FOR THE

CONSTRUCTION OF THE BIG STONE II PROJECT

PREFILED REBUTTAL TESTIMONY

OF

THOMAS A. HEWSON, JR.

PRINCIPAL

ENERGY VENTURES ANALYSIS, INC.

JUNE 9, 2006

BIG STONE II

PARTNERS IN GENERATION

PREFILED REBUTTAL TESTIMONY OF THOMAS A. HEWSON, JR.

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BEFORE THE SOUTH DAKOTA PUBLIC UTILITES COMMISSION

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I. INTRODUCTION

Q: Please state your name.

A: My name is Thomas A Hewson, Jr.

Q: On whose behalf are you submitting testimony?

A: The proponents of Big Stone Unit II (the "Applicants").

Q: How are you currently employed?

A: I am a principal at Energy Ventures Analysis, Inc. ("EVA"), an energy consulting firm located at 1901 North Moore Street in Arlington Virginia.

Q: Please describe your educational and employment history?

A: I have 30 years of experience as an environmental consultant on energy issues. My responsibilities at EVA include conducting environmental studies of the electric power industry. These studies include assessments of the cost and performance of electric power environmental control options, development of environmental compliance strategies, emission allowance market forecasts, and evaluations of existing and proposed future environmental regulations on electric power operations. I have testified in several state proceedings and to Congress on the effects of proposed environmental regulations on individual state power production costs, on state emissions and on environmental benefits. A copy of my résumé and relevant work is provided as Applicants' Exhibit 30-A.

Q: On whose behalf are you submitting testimony?

A: I am submitting rebuttal testimony on behalf of the Applicants.

Q: Please describe the assignment you were given for this proceeding by the Applicants.

A: I was asked to review and comment upon the carbon dioxide ("CO2") market risks discussed in the direct testimony of Mr. Schlissel and Ms. Sommer of Synapse Energy Economics, Inc. ("Synapse") on behalf of the environmental advocacy groups. I was also asked to review and comment on the environmental externality values used by Dr. Denney of QSI Consulting on behalf of the staff of the Public Utilities Commission of South Dakota.

Q: Please summarize your testimony.

A: Carbon dioxide regulation can potentially influence the selection of the lowest cost generation technology alternative since it can potentially increase the environmental compliance costs for fossil fuel alternatives. These potential carbon dioxide regulatory compliance costs are highly dependent upon the type and severity of carbon regulation adopted and would likely be proportionately higher for higher carbon containing fossil-fuel options.

For the Big Stone Unit II project partners, the question is whether a significant project risk exists that future carbon dioxide compliance costs are likely to exceed the $14/ton CO2 "breakeven" price penalty (2005$) calculated by Burns and McDonnell and described in their report entitled Analysis of Baseload Generation Alternatives – Big Stone Unit II (September 2005), included as Exhibit 23-A.[1] At this $14/ton CO2 compliance cost, the proposed supercritical pulverized coal plant production costs would increase to the same busbar costs as the next cheapest combined – cycle gas turbine (CCGT) plus wind resource option.

[1] The $14 figure applies to an investor-owned utility ownership structure. The Burns & McDonnell evaluation concluded that, for a public power ownership structure, the corresponding figure is $23. Both numbers are in 2005 dollars.

Based upon my evaluation of existing and proposed state and federal carbon control actions, I conclude that, if carbon regulation is indeed adopted at some point in the future, the likely range of control costs would be significantly less than this $14/ton level, making the supercritical pulverized coal option the lowest cost resource option. My conclusion differs from the much higher carbon dioxide control cost range of $7.80-$30.50/ton with an estimated mid-point of $19.10/ton proposed by Mr. Schlissel and Ms. Sommer in their direct testimony. As outlined in my testimony, Mr. Schlissel and Ms. Sommer fail to give adequate consideration to the fact that the Minnesota Public Utilities Commission has adopted environmental cost values that do not apply to generation located outside the state of Minnesota, including the proposed Big Stone Unit II. In addition, they have failed to adequately consider that the Minnesota Commission's carbon dioxide value for in-state generation is $0.35-$3.64/ton, that the projected compliance cost of the northeastern states' Regional Greenhouse Gas Initiative is $1-$3/ton, and the legislation that Congress actively debated but ultimately rejected last year had control costs under $7/ton.

Dr. Denney in her testimony suggests that the South Dakota PUC, in its evaluation of the Applicants' proposal, should utilize quantified environmental externalities for several criteria pollutants, mercury and carbon dioxide. However, South Dakota is one of the vast majority of states that has elected not to use quantified environmental externalities, and the Commission should not depart from that practice here. In any event, there is no basis to utilize quantified externality values for Big Stone Unit II's expected emission of criteria air pollutants since such emissions will not cause violations of the National Ambient Air Quality Standards in or outside of South Dakota. There is also no basis to use quantified externality values for mercury since, as I understand it, the Applicants have now committed to emission controls at Big Stone Units I and

II that will result in there being no net increase of mercury emissions from Units I and II as compared with present operations. Finally, the quantified externality value of $8/ton for carbon dioxide that Dr. Denney proposes is, in my view, too high and is also not representative of the environmental impacts of carbon dioxide emissions.

II. CARBON RISK TESTIMONY OF SCHLISSEL AND SOMMER

Q: Do Mr. Schlissel and Ms. Sommer recommend a potential CO2 regulatory compliance cost for this proceeding?

A: Yes. In their direct testimony (pg. 23-24), they recommend that a CO2 compliance cost range of $7.80 to $30.50/ton[2] with a mid point of $19.10/ton CO2 be applied to the Big Stone Unit II technology choice decision. Both the Synapse mid-point and high-point estimates exceed the Burns and McDonnell's $14/ton "breakeven" cost and would suggest that CCGT with wind would become the partnership's lowest cost resource alternative.

Q: Can you determine how Mr. Schlissel and Ms. Sommer derived their high, medium and low range of CO2 compliance costs?

A: No. Their specific methodology is not immediately apparent. Synapse had not responded to our data request asking them to specify their methodology and produce their workpapers at the time my testimony was prepared. Accordingly, it is difficult for me at this time to determine why their numbers are well beyond the bounds (on the high-side) of what I would view as reasonable. It appears that their forecasted compliance costs are based on forecasted costs of compliance with CO2 control regimes set forth in certain bills introduced in

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[2] All Synapse CO2 prices are expressed in 2005$ and represent a long-term levelized cost. Other figures used in this testimony, such as the Minnesota Public Utilities Commission's externality values or the Burns & McDonnell breakeven cost numbers, are not levelized. However, because the Synapse numbers are so far above the range that I would consider to be reasonable, it is not necessary to re-calculate the Synapse numbers to make them exactly comparable to the other externality values explored in my testimony.

Congress that Mr. Schlissel and Ms. Sommer selected for inclusion in their analysis. See Figure 1, page 18 of their testimony. However, I am uncertain of their specific approach.

Q: Do you agree with Mr. Schlissel and Ms. Sommer that a $7.80-$30.50/ton CO2 compliance cost range with a $19.10/ton mid point price is appropriate?

A: No. I do not think $19.10/ton CO2 represents a reasonable mid-point estimate of the cost of complying with possible future CO2 regulation.

Q: How would you evaluate the carbon regulation risk of the proposed Big Stone II Power plant?

A: First, let me highlight the fact that the Minnesota Public Utilities Commission established environmental cost values for use in resource planning by electric utilities subject to the Minnesota Commission's jurisdiction. These values were established in a 1997 order as $0.30-$3.10/ton of CO2 (subject to escalation).[3] According to Burns and McDonnell, these values escalated to $0.35-3.64/ton by 2005. In a subsequent order, the Minnesota Commission decided that the values should not be applied to out-of-state generation (which would include Big Stone Unit II).[4] The Minnesota Commission held lengthy proceedings in developing these numbers and a large number of parties participated, including some of the same intervenors in this case. The proceedings were held in response to a statute passed by the Minnesota legislature directing the Minnesota Commission to adopt environmental cost values to be used in resource planning.

Mr. Schlissel and Ms. Sommer severely criticize the Applicants for failing to plan for possible future CO2 regulation. Testimony, pp. 19-21. But in the Applicants' data responses

[3] Order Establishing Environmental Cost Values, Docket No. E-999/CI-93-583, January 3, 1997.

[4] Order Affirming in Part and Modifying in Part Order Establishing Environmental Cost Values, Docket No. E-999/CI-93-583, July 2, 1997.

included as an exhibit to Mr. Schlissel and Ms. Summer's testimony, Otter Tail Power Company and other Applicants specifically state that it did what the Minnesota Commission had ordered it to do. Rather than speculate about future CO2 compliance costs, they applied the externality values (in this case the zero value) mandated by the Minnesota Commission. Moreover, the Burns & McDonnell *Baseload Generation Alternatives report – Big Stone Unit II* (September 2005) examined the impact on the project's economics of the \$0.35-\$3.64/ton values, even though the Minnesota Commission decided that these values should not apply to out-of-state generation.

Mr. Schlissel and Ms. Sommer dismiss the Minnesota Commission's environmental cost values on the ground that the values represent the Commission's estimate of the damage that potential global warming would cause, rather than an estimate of the cost of complying with future CO2 regulation. Testimony, p. 19. This criticism is wrong in at least two ways.

First, from a resource planning standpoint, it would be a strange result if the cost of control turned out to be higher than the cost of the damage the controls are intended to mitigate. In essence, Mr. Schlissel and Ms. Sommer are recommending to this Commission that it should assume a \$19.10 control cost when the Minnesota Commission, after a full contested case hearing the scope of which was specifically focused on establishing environmental externalities, estimated a damage impact of \$0.35-\$3.64/ton. Such recommendation makes little sense.

Second, it is clear from reviewing the Minnesota Commission's decision in the environmental cost case that it considered the cost of complying with future regulations. The Commission stated that it had considered various ways of developing environmental cost values, including examining potential costs of complying with future regulations. However, the Commission stated that, from a resource planning perspective, a damage cost methodology was superior.[5] Moreover, the Commission did consider but rejected testimony as to the cost of controlling CO2 based on possible future regulatory scenarios in the case.[6]

In sum, I don't see how the Applicants can be faulted for following the requirements of the Minnesota Commission as to carbon dioxide. It seems perfectly reasonable for them to have assumed a zero carbon dioxide value in keeping with the Commission's order. It was also reasonable for Burns & McDonnell to have assumed CO2 values of \$0.35-\$3.64/ton of CO2 (as escalated). Moreover, as stated, Burns & McDonnell's analysis examined the breakeven point at which a future carbon compliance cost would make a supercritical pulverized coal project at the Big Stone site less economic than alternatives, which is considerably higher than \$0.35-3.64/ton. I therefore think that Schlissel and Sommer's criticism of the Applicants' approach to this issue is inappropriate.

Q: Apart from the Minnesota Commission's environmental cost values, how did you assess the risk of future CO2 regulatory compliance costs?

A: Neither South Dakota nor the federal government has existing carbon dioxide control regulations that pertain to electric power plants. Therefore, the carbon regulation risk for power plants located in South Dakota is from a future legislative or regulatory action taken by South Dakota or the federal government.

To evaluate the risk of future carbon dioxide control programs that may apply to a new South Dakota coal-fired power plant coming online in 2011, I took a somewhat similar approach as Synapse by first examining existing regulations and public policies for control of carbon

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5 January 3, 1997 Order at 14.

6 January 3, 1997 Order at 9-10.

dioxide emissions that have been implemented in other states as well as the several proposed carbon control approaches that have been debated by the US Congress and some states. The state actions and proposed federal legislation help identify the possible range of any future regulation that may apply to the Big Stone II power plant that could influence its generation technology selection.

From this control program review, I next identified the carbon dioxide compliance costs from the alternative control regulation approaches. These cost ranges were then compared to the \$14/ton CO2 "breakeven" compliance cost (\$23/ton for the public power entities) from the Burns and McDonnell *Baseload Generation Alternatives report -- Big Stone Unit II* (September 2005). At this \$14/ton CO2 penalty, the proposed supercritical pulverized coal plant production costs would increase to the same busbar costs as the next cheapest CCGT plus wind resource option.

Q: Can you summarize your major conclusions from your evaluation?

A: The largest carbon dioxide regulatory risk for a new South Dakota coal-fired power plant would likely come from new federal (not state) regulation. While there is a material risk of future federal action of some kind, great uncertainty remains over the type of carbon control program that may be adopted (if it is) and when it may become enforceable. Under what appears to be the most likely scenario of federally-imposed CO2 controls (if such controls were adopted), the compliance costs would definitely be less than \$7/ton CO2 and perhaps a good deal less. This value is far less than the Synapse's mid-point cost of \$19.10/ton or their estimated cost range of \$7.80-\$30.50/ton. This compliance cost is also far less than the \$14/ton (and \$23/ton) CO2 penalty Burns and McDonnell calculated as required to make the CCGT plus wind technology option cost competitive with the proposed Big Stone Unit II. As a result, I believe that the possibility of future CO2 regulation does not invalidate the Applicants' decision that the pulverized coal option likely is their lowest cost baseload resource option.

Let me emphasize that I am not saying I believe a value near $7/ton CO2 represents a reasonable planning number. As discussed below, the Senate bill on which it is based was not considered in Committee and did not even receive a floor vote. There was no parallel legislation in the House, which is even less amenable to mandatory CO2 controls than the Senate. My point is that the only CO2 bill that had any momentum last year had a cap on compliance costs of under $7 per ton.

Q: Would a CO2 compliance cost number necessarily apply to all CO2 emitted by Big Stone Unit II?

A: Not necessarily. Cap and trade programs typically allocate allowances to existing units and sometimes reserve allowances for new units. Depending on when a CO2 regulatory program might be enacted and the nature of the program, allowances might be allocated for some of Big Stone Unit II's CO2 emissions. The Burns & McDonnell report, in its analysis of the breakeven point at which CO2 compliance costs could make Big Stone Unit II uneconomic compared with alternatives, was appropriately conservative in assuming that those compliance costs would apply to all of Big Stone Unit II's CO2 emissions.

In addition, in some program approaches, fuel suppliers, not fuel consumers, would have be subject to carbon emission requirements (e.g., the Senator Bingaman proposal discussed later in this testimony). In these cases, the carbon compliance costs may not necessarily be passed onto their utility customers if the pass-through would force the utility to choose a different resource option or different coal supplier.

A. GENERAL OVERVIEW OF CO2 REGULATORY APPROACHES

Q: In your review of carbon control programs that applied to the power industry, how many different program approaches did you identify?

A: Overall in my April 2006 review, I found similar programs that Synapse identified in their subsequent May 2006 report. I found that states had used seven different approaches to control carbon emissions growth from the power industry. These programs also incorporated most federal legislative approaches being debated by Congress. These policy program approaches included:

- Cap and trade programs
- Emission tax/fee programs
- Emission rate limitations
- Emission offset programs
- Environmental externality adder programs
- Renewable portfolio standards
- Energy conservation and efficiency programs

Q: Please describe the Cap and Trade Program approach.

A: Cap and trade programs set specific emission tonnage targets. Existing sources are provided emission credits that they can trade to meet their emission limit.

Overall, cap and trade program compliance costs and economic impacts vary significantly based on the tonnage cap selected and the program's emission trading provisions.

Q: Have cap and trade programs been implemented by any states?

A: Only two states (Massachusetts and New Hampshire) have adopted carbon emission caps for major existing coal and oil-fired power plants. Each of these states will credit state approved carbon offset/reduction projects towards compliance. In addition, New Hampshire and six other Northeastern states (Connecticut, Delaware, Maine, New Jersey, New York and Vermont) have formed the Regional Greenhouse Gas Initiative (RGGI). In December 2005, the states signed a Memorandum of Understanding that would establish a regional carbon dioxide cap and trade program. Each state has to obtain state regulatory or legislative authority for such a cap and trade program, so the program has not yet been implemented. Maryland passed legislation this year to join the RGGI program. Several states have also considered but not adopted cap and trade programs for in-state sources.

Q: Have cap and trade programs been considered by Congress?

A: Cap and trade programs have also been proposed in Congress, including the McCain-Lieberman Climate Stewardship Act, Senator Jeffords' Clean Power Act of 2005, Senator Carper's Clean Planning Act and Senator Bingaman's Climate and Economy Insurance Act of 2005. Emission targets, program provisions and carbon dioxide values vary significantly among these proposals.

Q: Are cap and trade programs in operation elsewhere?

A: Yes. The Chicago Climate Exchange operates a voluntary industrial carbon dioxide emission cap and trade program for 42 members. Participants voluntarily agree to meet an annual CO2 emissions cap and in return are allowed to trade carbon dioxide credits on an open trading market. Prices are posted ($3.54/ton on 5/30/06).

Q: What is an emission tax or fee program?

A: Emission tax/fee programs set a fixed price per ton of emission. In addition, an emissions tax can become the default program compliance approach used by some greenhouse gas (GHG) cap and trade programs by establishing a safety value credit price (Bingaman's Climate and Economy Insurance Act of 2005 selected a cap of $6.36/ton CO2 in 2010) to cap compliance costs. Emission taxes/fees generate easily quantifiable revenues and set differential environmental penalties for fossil fuels that can be added into the fuel cost. If the tax/fee is applied to the fuel supplier, it would impact the industrial, commercial and residential sectors in addition to the electric utility sector.

Q: What states have such a program?

A: Emissions taxes have been applied to new sources in only one state, Washington ($1.45/ton CO2).

Q: Please describe the emission rate limitation approach.

A: Currently, only two states, Massachusetts (1,800#CO2/MWh for 16 existing units) and Oregon (675#CO2/MWh for new units), require targeted sources to meet a carbon dioxide emission rate limit. Approved carbon dioxide offset projects can be credited towards this limit. The California Public Utilities Commission recently announced its intent to establish a carbon dioxide emission rate standard equivalent to a natural gas combined cycle plant for all new California power purchase agreements with contract periods greater than three years. Details for the California "environmental standard" have yet to be defined in a rulemaking proceeding. The compliance cost for the emission rate approach is heavily influenced by the strictness of the selected rate limit and offset credit policies for compliance.

Q: What is an emission offset program?

A: Emission offset programs for new power plants have been adopted in two states (Massachusetts, Washington). New power plants must provide sufficient carbon dioxide offset credits from qualifying projects to offset their projected emissions. The states cap compliance costs by allowing sources an alternative compliance option of paying $1.00 (Massachusetts) - $1.45 (Washington)/ton CO2 into a state carbon mitigation fund. Carbon offset credits have also been allowed towards compliance with state emission cap and emission rate requirements.

Q: What is an environmental externalities adder program?

A: Environmental externalities "adder" programs are used for new generation resource decisions. Some state Public Utility Commissions require that power suppliers apply GHG environmental externality values in their selection of the lowest cost power resource option. For example in Minnesota, the Commission directs that sources apply a CO2 externality value of $0.35-3.64/ton CO2 for determining their in-state power plant resource decisions. California applies an $8.00/ton CO2 environmental externality value to their resource decisions. This approach only indirectly controls GHG emissions by influencing new resource decisions.

Q: What is a renewable portfolio standard?

A: Renewable Portfolio Standard is a policy whereby a prescribed portion of a state's retail power market is set aside for only environmental friendly renewable power generation alternatives (e.g. wind, geothermal, biomass, solar). One justification for these standards has been that renewable energy alternatives would displace primarily fossil fuel generation and lower carbon emissions. Currently, the renewable set-aside power market should reach 250 TWh by 2030. South Dakota has not adopted a renewable portfolio standard, but two adjoining states (Iowa and Montana) have. Minnesota has a renewable energy objective, which requires utilities to make a "good faith effort" to produce 10% of their energy from renewable resources.

Q: Please describe energy conservation and efficiency programs.

A: Energy conservation and efficiency programs have also been used by regulated utilities in most states to reduce emissions growth. Often the program costs are recovered in the regulated utility rate base.

B. POSSIBLE FEDERAL REGULATION

Q: Is there a risk of future federal carbon dioxide regulation that would apply to the electric power industry?

A: There is, of course, a risk of future federal carbon dioxide legislation.

However, the character of potential future federal regulation, if adopted, remains very uncertain. Having said that, I believe that the $19.10 per ton figure advanced by Synapse as a reasonable "midpoint" estimate of the cost of complying with possible future regulation is highly overstated. A strong effort was made last year in the Senate as a part of the debate of the Energy Policy Act of 2005 to enact a program of mandatory CO2 controls proposed by Senator Bingaman. Although the Senate did not adopt such a program, it did adopt a resolution endorsing the need for a mandatory program of CO2 controls. However, the resolution stated that the program could not significantly harm the economy and must encourage comparable action by other nations that are major trading partners and key contributors to global emissions, e.g., China and India. This expressed desire by the Senate to ensure that the program does not harm the economy and fosters participation by our major Third World trading partners would seem to indicate that the most likely CO2 program that would emerge from the Senate would be relatively modest and phased in over time. Of course, the House of Representatives and the Executive Branch have not shown strong interest in adopting a mandatory CO2 control program at this time and instead are focused on encouraging new technology to reduce the GHG emissions intensity of the economy.

Q: Can you describe the bill proposed by Senator Bingaman?

A: Yes. Senator Bingaman's bill incorporated the recommendations of the National Commission of Energy Policy (December 2004). His bill would reduce the U.S. carbon intensity (emissions per unit GDP) by 2.4% per year from 2010 to 2019 and by 2.8% per year thereafter. The program would be applied to all fossil fuels and other non-fuel greenhouse gas emitters. Based upon Energy Information Administration (EIA) Annual Energy Outlook projections, the emissions targets would require a cumulative 10.5 billion metric tons CO2 reductions between 2010 and 2025, or 8 percent of covered emissions. The bill established a cap and trade program for the trading of CO2 allowances. The bill also established a "safety valve" carbon trading value of $7/metric ton of carbon dioxide or $6.36/short ton of carbon dioxide.[7] In other words, any entity needing CO2 allowances could purchase them at the maximum price of $6.36/ton. Overall, EIA estimated that the bill would lower the overall national GDP by 0.4% by 2025.

The bill did not go through the committee process. Instead, it was introduced as an amendment on the floor of the Senate but then withdrawn before a vote was taken on it. However, it did receive significant attention, in part because Senator Bingaman is the ranking minority member of the Senate Committee on Energy and Natural Resources and in part because Senator Domenici, the Chair of the Committee, was known to be in active discussions with him.

Other bills providing for more stringent CO2 caps and without the availability of a "safety valve" source of allowances at a capped price have also been proposed in Congress, both this year and in prior years, notably by Senators McCain and Lieberman, Senator Jeffords and

[7] Under the proposal, the 7$/metric ton safety valve price (in nominal $) in 2010 would increase by 5%/year.

Senator Carper. However, none have come close to enactment into law. Senator Inhofe, Chair of the Senate Committee on Environment and Public Works, is known to be openly hostile to any kind of mandatory CO2 controls.

Q: What are the prospects of legislation this year?

A: Senators Domenici and Bingaman have been in discussions regarding possible new legislation. They jointly co-authored a White Paper discussing possible legislative approaches and recently hosted hearings. However, as of May 2006, no new bill has yet been introduced by either of them. Senator Domenici has stated that it is unlikely that legislation will move this year.

Q: What do you conclude from the effort on the Bingaman bill?

A: It is difficult to predict the likelihood and character of possible Congressional action. Much depends on the outcome of future elections, and much also depends on the performance of the economy. For instance, it is difficult to tell whether currently high energy prices will affect the desire of Congress and the public to have legislation that will increase energy prices further. The $6.36/ton safety valve price may be a high-side estimate of future compliance costs, as the Bingaman bill was not adopted by the Senate, and in any event would have faced difficulty in the House. Of course, the $6.36/ton carbon dioxide price cap would be far less than the $14 (for IOUs) and $23/ton (for municipals and coops) "penalty" which would indicate that the proposed Big Stone Unit II was not least cost.

If $6.36/ton was considered too high to gather sufficient Congressional support last year, there is even less political support for any GHG control program with a CO2 price tag at $19.10/ton as projected by Schlissel and Sommer.

Q: You stated earlier that you thought that Mr. Schlissel and Ms. Sommer may have calculated their low, medium and high estimates of future CO2 regulation compliance costs

based on a number of bills introduced in Congress. Do you have a comment on such an approach?

A: In theory, there is nothing wrong with looking at a number of potential pieces of legislation rather than just one. However, it is unreasonable to expect that utilities should plan around legislation that has not moved in the past and has little likelihood of moving in the future (precisely because of the high compliance costs). In this regard, Figure 1 on page 18 of Mr. Schlissel's and Ms. Sommer's testimony is somewhat misleading. First, the blue triangle and blue diamond data points on the chart that furnish the most support for the Synapse high case are derived from the 2003 McCain-Lieberman bill, a bill that not only was not enacted but which had more ambitious emission reductions than the McCain-Lieberman bill introduced in 2005. Similarly, the orange squares that might also support the Synapse high case are based on the Jeffords bill, a bill that was not even reported out of committee. I therefore agree with Mr. Schlissel and Ms. Sommer that the Synapse high case is not a reasonable planning scenario. More importantly, I don't agree that it represents a realistic upper-bound case that would give credence to their Mid Case.

The Synapse Mid Case suffers from similar problems. It is built around the green circles (McCain-Lieberman 2005),[8] the blue circles (a different estimate of McCain-Lieberman 2003), a yellow triangle (a high-side estimate of Bingaman) and a purple triangle (an EIA estimate of allowance prices under the 2003 Carper bill). The 2005 McCain-Lieberman bill received even fewer votes than the now superseded 2003 McCain-Lieberman bill. As a result, at best those

[8] The green circles and green triangles refer to SA 2028. In early 2003, Senators McDain and Lieberman introduced S.139 (the blue circles and triangles). This bill provided for a program that would reduce CO2 emissions to 2000 levels by 2010 and to 1990 levels by 2016. However, later that year they introduced SA 2028, an amendment that deleted the second phase. In 2005, they introduced S.826 which provided for the same emission reductions as SA 2028.

bills should be considered to be a high-point rather than a mid-point estimate of compliance costs. Similarly, the EIA estimate of compliance costs for the Carper bill should be contrasted with EPA's much lower estimates for the same bill (the purple squares). Thus, the EIA data point should also be, at best, a high-end estimate, not a mid-point estimate.

Even, the Synapse low-case seems to be exaggerated. The yellow triangles are EIA's estimate of allowance prices under the National Commission on Energy Policy (NCEP) proposal that was the model for the Bingaman bill. The yellow triangles represent capped allowance prices, as provided for in the Bingaman bill, whereas the yellow triangles with black borders represent the NCEP proposal without caps (and therefore legislation that was not introduced). To reiterate, the Bingaman bill as introduced (the yellow triangles without black borders) and the Carper bill (the purple squares) are bills that did not even receive votes in the Senate. To say that these bills represent a low end of future compliance costs does not seem reasonable to me. Nor does it seem reasonable for the Synapse Low Case dotted orange line to start escalating away from the compliance costs of these two bills.

In sum, I do not believe the various bills that were analyzed in Mr. Schlissel's and Ms. Sommer's testimony support their low, mid and high case cost estimates. Indeed, the fact that the McCain-Lieberman 2005 bill had lower emission reduction requirements than their original 2003 bill, and that Senator Bingaman's bill included allowance caps, indicates that for a bill to actually become law, it will have to have lower rather than higher compliance costs. As stated, last year's Senate resolution that Mr. Schlissel and Ms. Sommer rely on as showing momentum for greenhouse gas legislation specifically provided that such legislation could not damage the economy. Such resolution argues against, rather than for, Synapse's mid-point projection of high compliance costs.

Q: Mr. Schlissel and Ms. Sommer state that "[d]uring the decade from 2010 to 2020, we anticipate that a reasonable range of carbon emission prices will reflect the effects of increasing public concern over climate change (this public concern is likely to support increasingly stringent reduction requirements)". Testimony, p. 16. Do you agree with this statement?

A: I don't agree that public concern over climate change will necessarily lead to public support of increasingly stringent climate change policies. In the first place, according to the Gallup News Service,

> *"Americans are more convinced than ever that the Earth is being affected by global warming, but they have still not grown especially concerned about it. Only a third predict global warming will pose a serious threat in their lifetimes."*
>
> *"Public concern about global warming has ebbed and flowed over the past 17 years, and although higher now than when it was last measured in 2004, it is no higher than it has been at several points in the past."*[9]

This recent poll found that the level of public concern has been fairly flat and has not increased since 1989 but is actually down ten percentage points from its peak in 2000. With no growing public support, I find no basis for Synapse's underlying forecast assumption that the US will adopt significantly stricter emissions caps and with significantly higher CO2 prices than what is being debated today by the current Senate and Regional Greenhouse Gas Initiatives approaches.

As the same Gallup poll discusses:

> *"[s]ince Gallup started measuring public concern about global warming in 1989, the issue has always placed near the bottom of a*

[9] Gallup News Service, April 07, 2006, "Americans Still Not Highly Concerned About Global Warming."

> *list of 10 environmental issues rated. Water pollution and toxic waste contamination lead the list this year, with more than 50% of Americans highly concerned about these. Air pollution and loss of tropical rain forests also rank higher than global warming. [Only] Acid rain [and extinction of species] rank lower."* [10]

Finally, Americans are also obviously very concerned about high energy costs, and there is no question that "increasingly stringent emission reduction requirements" will lead to increasingly higher energy costs. The cost of U.S. compliance with the Kyoto Protocol was estimated by a 1998 U.S. Department of Energy report[11] to increase electricity costs by 66-86 percent, increase gasoline prices by 45-52 percent and reduce the national GDP growth rate by between 0.8-4.2 percent. This is why, at least in part, the U.S. has not ratified it. Public rebellion against the high cost of carbon emission reduction requirements could offset any potential increased public desire for global warming policies.

The willingness to pay for very high cost CO2 reductions may be difficult to sell to the public since even aggressive program reductions are more than offset by Third World emission increases as countries such as China, India and Brazil continue to industrialize. China and India alone are expected to account for over 40 percent of the world's carbon dioxide emission growth over the next 20 years as their annual emissions grow by 6.4 billion tons CO2.[12]

Q: Mr. Schlissel and Ms. Sommer mention that multiple utilities believe greenhouse gas regulation will come and several have "incorporated assumptions about carbon regulation in their long term planning" (pg 9). Do you agree?

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[10] Id.

[11] Impacts of the Kyoto Protocol on US Energy Markets and Economic Activity (EIA-October 1998) SR/OIAF/98-03

[12] *Emissions of Greenhouse Gases in the United States 2004,* Energy Information Administration, Office of Integrated Analysis and Forecasting, December 2005, at p. 4

A: I agree that several utilities do consider greenhouse gas regulation risk in their planning. The more important question is how they quantify this risk and if the carbon dioxide cost is sufficient to change their fuel and generation technology selection. Duke Power — one utility specifically identified by Mr. Schlissel as believing that carbon regulation was highly likely — plans to build two 800 MW super-critical pulverized coal units at their existing Cliffside station for their next incremental baseload generation capacity additions. Obviously, Duke Power's carbon dioxide planning cost value used in their baseload capacity evaluation was less than their coal option's fuel price and generation production cost advantage.

Duke Energy and the Applicants are not alone in planning new coal-fired additions. EVA is currently tracking 143 announced new coal-fired power plant projects around the country representing a baseload capacity of 86,213 MW. Of these announcements, 80 projects (54,989 MW) selected pulverized coal technology as their lowest cost resource option. If utilities include the carbon dioxide regulation risk as suggested by Synapse, the economics for these 143 projects still favor their coal option as the lowest cost option.

C. POSSIBLE STATE REGULATION

Q: Do you have any evidence that the South Dakota legislature appears likely to adopt any carbon dioxide control proposals that may affect the Big Stone II generation technology decision?

A: No. It appears that the legislature has consistently opposed carbon dioxide regulation. In 1998, the South Dakota legislature debated passing a resolution urging the US government not to sign the Kyoto Protocol. In March 2005, the South Dakota Legislature passed House Resolution 1018 that stated, "South Dakota Legislature supports the Clear Skies Initiative if the final version does not contain carbon dioxide emission regulations or standards, and that the goal of carbon dioxide emission reductions instead be supported through research and encouraged on a voluntary basis."

Based upon this resolution and the lack of evidence of any serious consideration in the South Dakota legislature to adopt carbon dioxide regulation, it appears that any carbon dioxide control regulation that could apply to Applicants' new power plant resource decision would come from only federal (not state) action.

Q: Mr. Schlissel and Ms. Sommer testified as to various state efforts regarding carbon dioxide regulation. Is this information relevant to determining possible carbon regulation applicable to Big Stone Unit II?

A: Not directly. Obviously, regulations adopted in California or the Northeast do not apply in South Dakota, nor is it immediately apparent why regulations adopted in those states would be persuasive. Nevertheless, it is worth examining the types of regulation other states have actually imposed to obtain some sense as to the type of legislation Congress might adopt or at least consider.

Q: Do you have any overall conclusions based on state actions to date?

A: Yes. Those actions in no way support the notion that the country is facing future CO2 compliance costs of $19.10/ton of CO2.

The first thing that becomes clear from a review of state activity to date is how limited it is in terms of mandatory CO2 emission controls. As stated by Mr. Schlissel and Ms. Sommer, only four states to date have actually mandated greenhouse gas reductions from power plants. See Table 5.3 of Exhibit F to their testimony. Of these four, only three, Massachusetts and New Hampshire for existing units and Oregon for new units, have actually capped carbon emission rates. Each state, however, will credit state-approved carbon offset/reduction projects towards compliance, greatly lowering the cost of compliance. Moreover, unlike South Dakota and the rest of the country, none of these states relies on coal-fired electricity for a large percentage of their electric generation (Massachusetts: 25%; Oregon: 7%; South Dakota; 46%; the country; 50%).

Another state (Washington) does not cap power plant emissions but requires carbon offsets at a cost of $1.45/ton. Moreover, like Massachusetts and Oregon, Washington utilizes relatively small amounts of coal for electric generation (10%).

Schlissel and Sommer's Table 5.3 also indicates that California has decided to adopt a load-based cap on greenhouse gas emissions. It is true that the California PUC has decided to adopt such a cap. However, it has not taken final action, so it is difficult to evaluate the program. California also is not a large user of coal-fired electricity (18%). It is hard to discern from the activity of these states that the country is on a path to adopting CO2 regulations that will cost $19.10/ton to comply with.

Q: Mr. Schlissel and Ms. Sommer also mention various state requirements for consideration of greenhouse gas emissions in electric resource planning decisions. Do these requirements support a $19.10 compliance cost figure?

A: No. Again, the most striking thing about their compilation of these resource planning requirements in Table 5.4 of their exhibit F is how limited these efforts are. They list a total of seven states plus the Northwest Power and Conservation Council with these requirements, one of which is Minnesota with the low numbers I discussed earlier. Even California's resource planning number of $8/ton is much less than Schlissel and Sommer's $19.10 number. Of course, South Dakota has never adopted an environmental externality requirement. This does not appear to be a groundswell to me.

Q: Mr. Schlissel and Ms. Sommer also refer to actions by various utility companies to consider possible carbon risk in resource planning. Can you comment on this testimony?

A: They testify that "several electric utilities and electric generation companies" consider carbon risk. Again, I don't see why the practices of "several" companies in an industry that has hundreds of electric companies should be taken as setting the norm or indicating a trend.

Q: You stated earlier that several states have joined the Regional Greenhouse Gas Initiative that is designed to control carbon dioxide emissions from power plants and other major fossil fuel fired facilities. Would you describe this program?

A: On December 20, 2005, seven states (Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont) signed a memorandum of understanding to adopt a regional greenhouse gas control program.[13] This program would establish a CO2 cap and trade system for participating states that would become effective January 1, 2009 for 370 fossil fuel burning power plant sources having capacities greater than 25 MW.

These affected sources had CO2 emissions totaling 114.5 million tons in 2004. Beginning in 2009, the regional emission cap would be set at 121.3 million tons. This is 5.9 percent above current emission levels and 9.1 percent above 1990 levels. This tonnage cap would be maintained for six years (through 12/31/2014) before being decreased by 10 percent over the following four years, reaching 109.1 million tons/year in 2018. This final cap limit is 4.7 percent below 2004 emission levels.

[13] Initially Massachusetts and Rhode Island were part of this initiative but elected not to sign the agreement due to concerns on its impact on state economic growth.

States would set-aside 25 percent of their allocations for an annual auction to establish (1) a strategic carbon fund for supplemental GHG emission reduction and sequestration projects and (2) a public benefits fund for energy efficiency, renewable and ratepayer mitigation projects.

The program provides for limited use of offsets for compliance. Eligible offset projects for compliance credits include: landfill gas capture and combustion; sulfur hexafluoride capture and recycling; afforestation (transition from non-forested to forested land); end-use efficiency improvements for natural gas, propane and heating oil; methane capture from farming operations, fugitive emission reductions from natural gas transmission and distribution and other methods if approved by all participating states. In an effort to moderate the price of CO2 allowances, the program provides that emission sources may increase their utilization of offset credits if the market price for allowances rises to certain trigger thresholds.

RGGI states completed an economic impact analysis of the proposed program in December 2005 using the EPA/ICF IPM model. The RGGI analyses projected CO2 allowance prices of:

- 2009 $1.00/ton ($2003$)
- 2012 $1.18/ton
- 2015 $1.44/ton
- 2018 $1.76/ton
- 2021 $2.15/ton
- 2024 $2.62/ton

The RGGI program has not yet been adopted by any of the signatory states. Adoption will require legislative or regulatory action by these states. Thus, it is not yet known exactly what type of program will ultimately emerge.

These estimated RGGI CO2 allowance costs are far less than the CO2 values being proposed by Schlissel and Sommer. Given that cost was an important consideration in the RGGI plan development, it is reasonable to assume that if participants thought CO2 prices would rise to $19.10/ton as suggested by Synapse, the project would have not gotten the needed support and the goals and trading programs would have been set very differently.

Q: What, if anything, does the RGGI program tell us about the likelihood and character of CO2 regulation that might be applied to Big Stone Unit II?

A: First, the RGGI program obviously does not apply in South Dakota. Moreover, it does not seem likely that the willingness of the Northeastern states to adopt this program will influence South Dakota to adopt a similar program of its own. Unlike South Dakota, none of the Northeastern states participating in the program produce coal and none utilize significant amounts of coal for electric generation[14] that would have increased compliance costs.

However, it is noteworthy that even the states most aggressively pursing mandatory CO2 controls and with the least to lose by doing so chose to recommend adoption of a program with modest control targets and therefore modest control costs. Some states elected not to participate in the RGGI process because of strong concerns about the economic impacts of control

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[14] According to DOE Electric Power Monthly- March 2006, coal accounted for only 15.3% of 2005 in-state generation from RGGI states. This is far less than the coal market share in South Dakota (46.1%) or the national average (50.4%)

measures. Thus, RGGI would seem to reinforce my conclusion that CO2 controls, if adopted nationally, are likely to have relatively modest and phased-in control costs.

Q: Mr. Schlissel and Ms. Sommer refer to lawsuits brought by states to compel greenhouse gas regulation. Can you comment on this testimony?

A: I'm not sure I understand the relevance of this testimony. There have been two such lawsuits. Generally, they have been brought by the same states, discussed above, involved in greenhouse gas regulatory efforts. Both lawsuits have so far been unsuccessful. The first involved an attempt to compel USEPA to regulate greenhouse gas emissions from motor vehicle tailpipes under the federal Clean Air Act. This lawsuit was unsuccessful in the U.S. Court of Appeals for the D.C. Circuit.[15] The states have asked the Supreme Court to review the case, but so far the Court has not acted on that request.[16]

The second lawsuit was brought in U.S. Federal District Court in New York City and claimed that greenhouse gas emissions from power plants in twenty states were causing global warming which constituted a "nuisance" which should be enjoined. An interesting fact about the lawsuit is that eight states joined in as plaintiffs, but only one of the plaintiff states had a power plant that was a subject of the lawsuit. The lawsuit was dismissed by the New York court[17] and is on appeal to the U.S. Court of Appeals for the Second Circuit.

Two lawsuits that have so far not had success does not seem to me create momentum for stringent CO2 regulation.

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15 *Commonwealth of Massachusetts v. EPA*, 415 F.3d 50(D.C. Cir. 2005).

16 I understand that these same states have recently filed another lawsuit in the D.C. Circuit pursuing the same theory as to USEPA New Source Performance Standards.

17 *Connecticut v. American Electric Power Company*, 2005 U.S. Dist. LEXIS 19964 (S.D.N.Y. 2005).

D. CONCLUSION

Q: Based on the above, what do you consider to be an appropriate planning number for the cost of complying with possible future CO2 regulation?

A: Assuming legislation is eventually adopted in Congress, I believe that the cost of compliance would be set at a value less, and probably considerably less, than $14/ton CO2.

As I testified earlier, the stringency of the carbon limit adopted is one factor in addition to the type of program approach and the use of flexible market trading and offset credit policies that heavily influence the CO2 price. Obviously, my disagreement with Schlissel and Sommer's CO2 price forecast is primarily the costs Americans are willing to pay that may ultimately set the U.S. GHG policies. Schlissel and Sommer have significantly overestimated the price that Americans are willing to pay. Their price projections are well above the CO2 price projections for both the adopted RGGI program and the Senate proposal that received the most attention in the Senate last year. Schlissel and Sommer's price forecast simply assumes much stricter emission tonnage caps without any longer-term cost caps or offset credit policies.

III. EXTERNALITY TESTIMONY OF STAFF WITNESS DENNEY

Q: Dr. Denny in her direct testimony suggests that the applicants should include several quantified environmental externality cost values (for emissions of particulates, carbon monoxide, volatile organic compounds, lead, mercury and carbon dioxide) in the project's economic evaluation to assure that the lowest cost option is selected. According to Denney's calculations, these environmental externalities would add $12-296 million to the selected supercritical pulverized coal option. Do you agree with Dr. Denney's approach?

A: I have some areas of disagreement. As an initial matter, as discussed earlier in my testimony, only very few states even recognize quantified environmental externalities in their utility planning. South Dakota is one of the vast majority of states that has elected not to use quantified environmental externalities. It would seem strange for South Dakota to even consider using externalities without the state having undertaken its own contested case or rulemaking proceeding to sort through the myriad of issues involved in adopting externalities before actually doing so. Thus, as a matter of policy, it seems that South Dakota should not be utilizing environmental externality values in this proceeding.

Dr. Denney suggests that environmental externalities should be used in this proceeding because she reads the South Dakota statutes and regulations as requiring that environmental impacts be "calculated" (Denney testimony pg. 22). I will leave it to the Commission to decide whether this is a correct reading. But if the South Dakota Commission is not required by law to use quantified values, I would expect that the Commission would not want to adopt this small minority approach to resource decision-making.

Q: How does Dr. Denney quantify environmental externalities?

A: In order to quantify what she sees as the environmental impacts of Big Stone Unit II, Dr. Denney recommends that the resource evaluation include environmental externality values for particulate matter (PM10),[18] carbon monoxide (CO), volatile organic compounds (VOC), lead, mercury and CO2. For her evaluation, she adopts the criteria pollutant externality values contained in an October 1998 EPA report entitled, "Federal Purchasing Categories Ranked by Upstream Environmental Burden: An Input/Output Screening Analysis of Federal Purchasing". She also adopts the mercury externality value from Resources for the Future June 2005 paper

[18] EPA currently has two air quality standards for Particulate Matter. One is for PM10, which is particulate matter with an aerodynamic diameter of 10 micrometers or less, and one is for PM2.5, which is particulate matter with an aerodynamic diameter of 2.5 micrometers or less. Dr. Denney's testimony addresses PM10.

"Reducing Emissions from the Electricity Sector." The value she uses for lead was from the Minnesota PUC's externality values. For CO2, Dr. Denney uses both the California CO2 externality adder of $8/ton as well a published range of CO2 externality values contained in the 1998 EPA report.

Q: What are your areas of disagreement with Dr. Denney's approach?

A: My first area of disagreement with Dr. Denney is with respect to the so-called "criteria" air pollutants for which she applies externality values (lead, PM10, CO, and VOCs).[19] The Applicants have shown that Big Stone Unit II will not cause a violation of USEPA's ambient air quality standards and I don't see anything in Dr. Denney's testimony to indicate she disagrees with that conclusion (indeed, no party appears to dispute that conclusion). Accordingly, Big Stone Unit II will not damage the public health or welfare and there is, therefore, no basis to assess an environmental externality.

By way of background, under the federal Clean Air Act, USEPA is required to set National Ambient Air Quality Standards (NAAQS) to protect both the public health (primary NAAQS) and environmental welfare (secondary standards). USEPA is required to set these standards based upon a detailed review of all existing scientific studies compiled in a "Criteria Document." USEPA's science is reviewed by an independent Clean Air Science Advisory Committee. USEPA sets its primary NAAQS at levels to protect the public health with an additional adequate margin of safety. Secondary NAAQS standards are similarly set to protect against other known environmental welfare impacts (such as crop damage from air pollution,

[19] There are currently six criteria air pollutants: sulfur dioxide, nitrogen oxides, ozone, PM, lead, and CO. Although VOC is not itself a criteria air pollutant, VOCs are an air quality concern because it leads to the creation of ozone (which causes smog) that is a criteria pollutant.

visibility impairment, etc.). Once the NAAQS are established, the states (subject to USEPA review) determine areas that are in attainment with the NAAQS and areas that are in nonattainment with the NAAQS (or unclassifiable areas). Nonattainment areas are subject to elaborate requirements to foster attainment within set timelines.

Since the project will not cause any areas to be in nonattainment, by definition the project can be presumed not to cause any health or welfare impact. And since an environmental externality is an otherwise unpriced environmental impact, there is no basis to apply externality values for the criteria pollutants in this case. This adjustment would reduce Dr. Denney's calculated externality damage values by $4.4-34.2 million by eliminating the externality calculations for CO, PM10, VOC and lead.

Dr. Denney states that even if Big Stone Unit II air emissions do not create local nonattainment problems, such emissions could nevertheless cause environmental impacts justifying the use of externality values. She states "air emissions are often transported hundreds of miles away, thus contributing to air pollution in other areas." She also refers to the negative effects of mercury emissions that are not accounted for in the NAAQS program. Testimony, p. 31, lines 13-18.

I agree that the NAAQS program does not apply to mercury and that compliance with the NAAQS does not eliminate potential environmental impacts of mercury (but see below for my discussion of mercury impacts). However, the NAAQS program does apply to the criteria air pollutants for which Dr. Denney has assessed externality costs (CO, lead and PM10). CO, lead, and PM10 are not pollutants that can travel "hundreds of miles." Nonattainment for these pollutants has never been associated with long-range transport. EPA recently adopted regulations addressing long-range transport of pollutants emitted by electric generators in order to deal with the problem Dr. Denney highlights, that is, local nonattainment caused in some part by pollutants blowing in from distant sources.[20] But that program addresses the issue of sulfur dioxide and nitrogen oxides emissions that are transformed in the atmosphere into fine particulates and ozone. Moreover, that program does not apply in South Dakota, because there is no evidence that nonattainment is materially affected by the long-range transport of emissions originating in the West (including South Dakota).

I note that Dr. Denney states that "Staff's calculation of the environmental impacts should be considered as a 'pessimistic scenario' rather than an 'average scenario'" precisely because Big Stone Unit II is located in a rural area far from urban populations. Denney Testimony, p. 32, lines 5-7. But without any evidence at all that Big Stone Unit II's emissions of criteria pollutants even theoretically create nonattainment, I would respectfully suggest that better policy is not to quantify a value for these pollutants at all.

Q: Do you think it was appropriate for Dr. Denney to estimate an externality value for mercury?

A: No, it wasn't, because Dr. Denney's approach to estimating externality values is inapplicable for mercury in this case now that the Applicants have made a commitment to reduce mercury emissions from Units I and II to no more than what is presently emitted from Unit I alone. Terry Graumann of Otter Tail discusses this commitment in his rebuttal testimony (Applicants' Exhibit 34). Dr. Denney determined that the externality value for sulfur dioxide is zero because there is no net increase in emissions. She testifies, "because of the projected zero net emissions of sulfur dioxide, Big Stone II's environmental impact from sulfur dioxide is

[20] *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule), etc.; Final Rule*, USEPA, 70 Fed. Reg.25, 162 (May. 12, 1995).

zero." Testimony, p. 24, lines 9-11. The same logic would lead to the conclusion that there is no externality value for mercury because there will be no increase in mercury emissions.

Q: Do you have any other concerns about determining an externality value for mercury?

A: Yes. Regardless of whether mercury emissions increase or not, developing any externality values for mercury is a very difficult process, even more so than for other pollutants,. The effect of mercury emitted by power plants on human health is indirect. Mercury emitted by power plants is generally transported very long distances in the atmosphere (although, depending on the type of mercury in the coal, some portion can be deposited locally). Mercury deposition becomes a concern when it is deposited in fresh or sea water and "methylizes" into methyl mercury. Methyl mercury bioaccumulates in fish flesh. The consumption of fish with high methyl mercury content is a concern for nursing women or women of child-bearing age, as high blood levels of mercury in children can cause small but measurable learning disabilities (at the levels that can be caused by fish consumption). Calculating the monetary damage that is caused by mercury emissions from a coal plant is therefore highly complicated – involving determination of mercury emissions, transport ranges, deposition rates, methylization rates, bioaccumulation rates, fish consumption patterns, any resulting learning disabilities and other health effects, and the monetary value of those effects.

Because of the complicated nature of this process, the Minnesota Commission, in its environmental externality proceeding, determined it was not practicable for it to calculate a mercury externality value. Among other difficulties, the Commission determined that:

> current models do not exist to account for the complexity of the atmospheric chemistry of mercury and its deposition; the record contains insufficient data regarding the amount and form of mercury emissions

> from coal combustion. The form of mercury emitted not only determines how much of the mercury may be removed, but it also determines the fate, health effects and risk assessment of the mercury emissions; a third area of omissions and uncertainty in data is the amount and form of mercury emissions from natural as compared to anthropogenic sources; also missing are data and models to estimate accurately the effect of changes to mercury in contaminated fish.[21]

Of course, none of this type of information as to the effects of Big Stone Unit II's emissions exists in the present record.

The externality values Dr. Denney provided for mercury ($2,500-$36,650/lb) are based upon estimated mercury reduction benefits from a Resources for the Future June 2005 paper "Reducing Emissions from the Electricity Sector that in turn drew upon a 2005 study by Rice & Hammitt for NESCAUM[22] entitled "Economic Evaluation of Human Health Effects of Controlling Mercury Emissions from US Coal-Fired Power plants." This wide cost range of $2,550-$36,650/lb is primarily associated with, in the phrase of the NESCAUM report, its "somewhat more controversial" premature mortality estimates. The reason these estimates are admittedly controversial is because they depend upon the assumption on methyl mercury intake from fish consumption and its dose response contribution to premature death from heart attacks.

Equally important, the NESCAUM study does not tell us anything about the specific effects of Big Stone Unit II. Big Stone II will utilize a wet flue gas desulphurization system (FGD). This system will remove the oxidized mercury of the coal used at Big Stone. Oxidized mercury, when combusted in a coal plant, tends to be deposited locally. Thus, the only Big Stone Unit II mercury emissions will consist of elemental mercury that does not deposit locally.

[21] *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule), etc.; Final Rule*, USEPA, 70 Fed. Reg.25,162 (May 12, 1995).

[22] NESCAUM is the Northeast States for Coordinated Air Use Management, an association of air quality departments in the Northeast

Accordingly, Big Stone Unit II will join other U.S. power plants that account for only an extremely small portion of the world's mercury reservoir so that differences in its impact to non-local deposition may not be attributable or measurable (only about three percent of elemental mercury emissions deposited in the U.S. are originally emitted by U.S. power plants). I am not contending that Big Stone Unit II's mercury emissions will not have any health or welfare impact (although such impact, if measurable at all, would be exceedingly low). Thus, for all these reasons, it would be very difficult to determine a quantified externality value for Big Stone Unit II's mercury emissions.

Q: What are your concerns as to Dr. Denney's carbon dioxide value?

A: Most of Dr. Denney's environmental externality costs were from calculated carbon dioxide damages — $67.5-255 million/year. These calculations were built upon a large carbon dioxide cost range of $1.50-$51/ton that was developed from a 1995 literature survey. The higher values are well above current externality values used by some utilities in generation planning in the US — including Minnesota. Moreover, it is difficult to determine and comment on the source of these numbers.

Dr. Denney recommends that this Commission utilize the California $8/ton CO2 resource planning adder to estimate the environmental damages of CO2. However, there is a conceptual problem in doing so. Dr. Denney states that her purpose in developing externality numbers is to calculate the impact on the environment of Big Stone Unit II's emissions. Testimony, p. 22, line 18 (note also that Dr. Denney's environmental externality testimony is in the section of her testimony entitled "Environmental Impacts"). The California adder, however, was not developed to estimate the environmental damage that would result from CO2 emissions. It was developed to estimate the cost of compliance with possible future CO2 regulation – a different concept. It is therefore not a logically relevant number for Dr. Denney's purpose.

In contrast, Minnesota did try to quantify the environmental damage of carbon dioxide in its 1997 environmental externality hearings. Based upon the evidence presented, Minnesota set its carbon dioxide environmental externality value at a range that has now escalated to $0.35-$3.64/ton for plants located in Minnesota. Given the similarities in climate and location, the Minnesota estimate would have provided a much better estimate than the California planning value. If this Minnesota value is applied, the dollar cost impact of the project's CO2 emissions is obviously greatly reduced from Dr. Denney's calculations.

IV. CONCLUSION

Q: Does that conclude your testimony?

A: Yes, it does.

RESUME OF
THOMAS A. HEWSON JR.

PROFESSIONAL EXPERIENCE

1981-Present **Energy Ventures Analysis, Inc.**
Principal

Responsible for power industry market studies. Provides regular power industry forecasts of future electricity demand growth, generation mix, environmental compliance and production cost changes for Fuelcast subscribers and individual client studies. Completed numerous studies examining the effect of future environmental regulation and utility deregulation on fuel prices, supplier capacity decisions (new, repower, retire), generation/environmental technology choice, wholesale electric prices and emission allowance values. Provided market assessments for new fuel, generation and pollution control technologies. Directed industrial utility group examining repowering technology options, costs and risks. Completes studies on renewable power options, costs, incentives and price impacts. Performs assessments of electricity demand, energy conservation potential and alternative energy charge frameworks for power consumers.

Responsible for corporate emission allowance forecasts and assessments. Provides ongoing forecasts of emission trading market prices and fundamentals of existing Acid Rain SO2 market, seasonal NOx market, CAIR, RGGI and individual state new source offset markets. Assesses future market trading values for mercury and carbon dioxide. Evaluates wide range of state legislative multi-pollutant proposals and their effect on regional production costs, state GDP, and environmental benefits. Engaged in developing new rules and regulations to expand existing emission allowance trading markets to include non-traditional sources (e.g. mobile sources).

Directs technical feasibility and environmental permitting studies. Expert in electric utility repowering technologies, fuel upgrading and environmental control technologies. Work includes several plant specific analyses on the costs of reducing SO2 emissions through allowance purchases, switching to lower sulfur fuels, least emission dispatching, plant retirements, repowering and FGD scrubber retrofits for all major coal and oil fired utility stations. Examined feasibility/costs of hazardous waste treatment/disposal for all major industrial waste streams in Louisiana.

1976- 1981 **Energy and Environmental Analysis, Inc.**
Project Manager

Responsible for environmental and regulatory analysis. Examined, for governmental and industrial clients, the requirements and associated impacts on current industrial practices of the Clean Water Act, Clean Air Act, Resource Conservation and Recovery Act, Toxic Substances Control Act, Safe Drinking Water Act, Fuel Use Act, Natural Gas Act, Natural Gas Policy Act, Surface Mining and Reclamation Act and Occupational Safety and Health Act. Results of these policy, economic and technical analyses have been used for Congressional hearings, EPA rulemaking, court testimony, industrial policies, administrative hearings and permit negotiations. Developed Federal and state regulatory compliance strategies for the Department of Energy and

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EXHIBIT
APPLICANTS
EXHIBIT 3

several industrial clients. On behalf of several clients, he has applied for construction, NPDES, air, solid waste, hazardous waste, water use and land use permits.

Responsible for solid waste/hazardous waste management analyses. Evaluations have included analyses of solid waste and hazardous waste treatment/disposal options for the fertilizer, fermentation ethanol, petrochemical, inorganic chemical, electric utility, synthetic fuel, pulp and paper and mineral processing industries.

Publications

Mr. Hewson has presented and published several papers on the electric utility industry and emission allowance markets. Also co-author on two papers on innovative wastewater treatment technologies.

Educational Background

1976 B.S.E. (Civil Engineering), Princeton University.

Mr. Hewson was appointed for a 3-year term as a Member of the Alexandria Environmental Policy Commission in 2005.