LARGE FILING SEPERATOR SHEET

CASE NUMBER: 06-1358-EL-BGN

FILE DATE: 10/25/2007

SECTION: 2 of 4

NUMBER OF PAGES: 161

DESCRIPTION OF DOCUMENT:

Exhibits

BEFORE THE
OHIO POWER SITING BOARD

Application of American Municipal Power, Ohio, Inc. (AMP-Ohio) for a Certificate of Environmental Compatibility and Public For the American Municipal Power Generating Station in Meigs County, Ohio	)))))	Case No. 06-1358-EL-BGN

DIRECT TESTIMONY OF
RICHARD C. FURMAN

ON BEHALF OF

NATURAL RESOURCES DEFENSE COUNCIL
OHIO ENVIRONMENTAL COUNCIL
SIERRA CLUB

October 25, 2007

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I. BACKGROUND AND WORK EXPERIENCE

Q. Please State Your Name and Address for the Record.

A: My name is Richard C. Furman. My address is 10404 S.W. 128 Terrace, Perrine, Florida 33176.

Q: What Is Your Occupation?

A: I am a retired consulting engineer, and I volunteer my time to advise utilities, government agencies, environmental groups and the public about the potential benefits of using coal gasification technologies. I have testified in previous permit hearings for proposed coal plants concerning emission control technologies, applicable emission regulations and alternative technologies concerning Mercury, NO_x, SO_2, particulate and CO_2 emissions and their associated costs.

Q: How Long Have You Been Retired?

A: Since February 2003.

Q: What Was Your Occupation Before You Retired?

A: During my entire engineering career, I have worked on new energy technologies, alternative fuels for power plants, and pollution control for power plants. Prior to my retirement, I was an independent consulting engineer for 22 years to various utility companies, government agencies, process developers and research organizations on the development, technical feasibility and application of new energy technologies and alternative fuels for power plants.

Q: What Did You Do Before You Were An Independent Consulting Engineer?

A: Prior to my work as a consulting engineer, I managed Florida Power & Light's coal conversion program and fuels research and development program, which included the first conversion of a 400 megawatt (400MW) power plant from oil to a coal-oil mixture to reduce oil consumption after the second oil embargo. Prior to this, I directed the engineering study for the conversion of New England Electric's Brayton Point Power Plant, which was the first major conversion of a power plant from oil to coal after the first oil embargo.

My first engineering job was working for Southern California Edison Company to modify their power plants for two-stage combustion to reduce nitrogen oxide emissions in 1969.

Q: **Please Summarize Your Formal Education.**

A: I received my B.S. in Chemical Engineering from Worcester Polytechnic Institute in 1969 and a M.S. in Chemical Engineering from Massachusetts Institute of Technology in 1972. I was a researcher at MIT for the book entitled <u>New Energy Technologies</u> by Hottel and Howard. After researching for this book, I decided to do my Master's thesis on coal gasification because of its potential as a future energy source and its environmental benefits. My Master's thesis at MIT was entitled <u>Technical and Economic Evaluation of Coal Gasification Processes</u>. I was also a teaching assistant at MIT for the courses of <u>Principles of Combustion and Air Pollution</u> and <u>Seminar in Air Pollution Control</u>. A copy of my resume is attached as Exhibit RCF-1.

Q: **How Does Your Education and Experience Prepare You to Provide Expert Testimony in this Case?**

A: Both my education and work have required an in-depth understanding of past, present and new forms of energy technologies that can be used for power plants. My education and work experiences also involved an in-depth understanding of all the various fuels for power plants including the different types of coals, fuel oils, natural gas, petroleum coke, synthesis gas, biomass and refinery wastes. My graduate education and subsequent work experiences have provided me with a detailed understanding of the techniques and costs for controlling power plant pollution including mercury, NO_x, SO_2, CO, particulate matter and CO_2 emissions. My prior work for 3 major electric utility companies allowed me to make use of this knowledge to help develop and utilize new fuels and emission control technologies for power plants. My current volunteer experience allows me to keep informed about the latest developments in new energy technologies, coal gasification technologies, fuels for power plants, techniques for controlling power plant emissions, costs associated with the application of these technologies for power plants and the development of new technologies that may be applicable to power plants.

II. SUMMARY OF TESTIMONY

Q: What Is Your Expert Opinion About the Proposed Pulverized Coal Plant?

A: The proposed pulverized coal (PC) plant does not represent the minimum adverse environmental impact, considering the state of available technology and the nature and economics of the various alternatives. My testimony shows that an IGCC plant can eliminate between 40 and 93% of the various air pollutants that the proposed PC plants will emit. Various studies have shown that IGCC plants can capture CO_2 at much lower costs than pulverized coal plants. My testimony shows how an IGCC plant can provide electricity at a lower cost than a PC plant. Many utilities around the country are choosing IGCC plants due to IGCC's much lower emissions of all pollutants and its capability to capture CO_2.

The proposed pulverized coal (PC) plant does not serve the public interest, convenience and necessity due to the adverse risks that these PC plants have for significant increases in costs and water consumption to meet future environmental regulations. My testimony shows that, in comparison to a pulverized coal plant, IGCC technology allows for the production of power from coal with significant fewer environmental impacts, and provides the best option for C02 emissions reduction on a coal power plant. Studies by the US Department of Energy, US Environmental Protection Agency, the Electric Power Research Institute, major universities and the electric power industry's engineering firms have concluded that both capital costs and the cost of electricity are lower for IGCC technology with C02 capture than for any other coal based generating technology.

The proposed pulverized coal (PC) plants do not incorporate the maximum feasible water conservation practices. After considering the available technologies and the nature and economics of the various alternatives my testimony shows that the proposed design for the AMPS-Ohio plants will consume 55% more water than the same size IGCC plant. If CO2 capture is required the water consumption for the proposed AMPS-Ohio plant will likely be 200% higher than an IGCC plant with CO2 capture. These are significant additional financial and environmental risks caused by the proposed PC plants.

IGCC's advantage arises from the fact that the C02 and other pollutants are captured prior to combustion. This allows the removal from the much smaller volume of syngas prior to combustion rather than the much larger volume of flue gas after combustion. Prior to combustion the syngas is under high pressure and does not contain the large quantities of atmospheric nitrogen that is present in the post-combustion flue gas. Both of these factors make the volume of the flue gas more than 100 times larger than the volume of the syngas. The equipment necessary for emission control on an IGCC unit is smaller because there is a small volume of gas to be processed relative to post combustion flue gas.

Various studies have shown that CO2 capture would be less costly from an IGCC plant than from a PC plant. The most recent and comprehensive studies on CO2 capture and storage are:

The Future of Coal, by the Massachusetts Institute of Technology (MIT), published in April 2007 and the Cost and Performance Baseline for Fossil Energy Plants, by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL), published on May 15, 2007. This NETL study shows that CO2 capture and storage will increase the cost of electricity by 85% for the AMPS-Ohio plant (Sub-critical PC design). This same study indicates that CO2 capture and storage will increase the cost of electricity by 32% for an IGCC plant. This much higher cost for CO2 capture from the proposed AMPS-Ohio plant is a significant financial risk.

For IGCC plants, the processes and technology required to capture CO2 from syngas are known and currently being used commercially at numerous industrial, non-power generation gasification facilities around the world. In addition, the processes and technology required to inject CO2 into deep geologic formations are also currently being used at several sites, including the Dakota Gasification Plant in Beulah, North Dakota, which currently sells over 1 million tons per year of CO2 for use in enhanced oil recovery.

While it is true that there are no operating IGCC power plant facilities currently capturing CO_2 for geologic injection , all of the technical issues associated with CO_2 capture and injection at an IGCC power plant have been commercially demonstrated at other, non-power plant gasification facilities. Installation of CO2 capture equipment at IGCC plants has not occurred due primarily to the cost of the equipment, the impact to the unit's operation and the belief that there is no regulatory requirement to control CO2 emissions.

No method of CO_2 capture is commercially available or economically viable for the proposed pulverized coal power plants. Research & Development (R&D) has only started on technology that may be capable of capturing CO_2 from Pulverized Coal (PC) plants. It will take many years before these R&D projects determine if these new technologies are technically and economically feasible at commercial scale.

The recent DOE report Cost and Performance Baseline for Fossil Energy Plants, by the NETL, May 15, 2007 shows that the proposed design for the AMPS-Ohio will consume 55% more water than the same size IGCC plant. This study also indicates that if CO2 capture is required the water consumption for the proposed AMPS-Ohio plant will require 200% more water than an IGCC plant with CO2 capture. These are significant additional financial and environmental risks caused by the proposed PC plants.

My testimony presents comparisons of recent permit applications for IGCC plants versus the proposed AMPS-Ohio PC plants that show significantly lower emissions for the IGCC plants. My testimony also presents comparisons of recent permit applications for other PC plants versus the proposed AMPS-Ohio PC plants that show lower emissions for the other PC plants. Therefore the proposed AMP-

Ohio plant does not have the minimum adverse environmental impact possible.

Commercial IGCC plants have been in operation in the U.S. for more than 10 years. Chuck Black, the president of Tampa Electric Company, was quoted in Time Magazine (November 2006) as saying **"it's our least cost-generating resources, so we count on it and use it every day as part of our system"**. Today there are approximately 130 gasification plants worldwide that produce fertilizers, fuels, steam, hydrogen and other chemicals, and electricity. Of these 130 plants, seventeen are IGCC plants. These IGCC plants have a capacity of about 4,000 MW(net) and have almost one million hours of operation.

The Great Plains Synfuels Plant has been gasifying coal since 1984 to produce synthetic natural gas (SNG). Since 2000 this gasification plant has been capturing its CO_2 and transporting it 205 miles by a new pipeline where it is injected underground in connection with enhanced oil recovery. This demonstrates that CO_2 can be captured, compressed, and transported from a commercial gasification plant for geologic injection.

The Eastman Chemical Company has been removing the mercury from their gasification plant for more than 20 years. Recent testing indicates that the mercury levels in the cleaned gas are at non-detectable levels. This level of mercury removal can not be obtained from PC plants.

IGCC plants are capable of using lower cost fuels including petroleum coke (petcoke), biomass wastes and renewable energy crops.

IGCC plants produce less solid wastes and less potential for ground water contamination than the proposed pulverized coal plant.

III. PULVERIZED COAL COMBUSTION AND GASIFICATION TECHNOLOGIES

Q. What are the Differences Between Combustion and Gasification?

A: It is important to understand the difference between combustion which is used in a coal power plant and coal gasification which is used in an IGCC plant. Exhibit RCF-2 shows the differences between combustion and gasification. The coal boiler operates at 1800 F and atmospheric pressure. The coal gasifier operates at 2600 F and 40 atmospheres pressure. The flow meters show the pounds of material that need to be processed for the same amount of electricity. Prior to gasification the nitrogen is separated from the air and the oxygen alone is used in the gasifier. Therefore for the same amount of electricity the gasifier produces 173 pound of synthesis gas versus 1000 pounds of exhaust gas from the boiler. Since the gasifier operates at higher pressure there is also a much smaller volume of gas that needs to be treated for pollutants and therefore the size of the equipment and capital cost is much smaller. The exhaust gas volume that needs to be treated from a coal boiler is 160 times larger than the volume of the synthesis gas that can also be cleaned of pollutants. The form of the pollutants from the gasifier makes it possible for very efficient recovery of potential pollutants using proven commercially available equipment that is operating in the natural gas and petrochemical industries. Proven commercially available technologies are <u>not</u> presently available for the proposed new coal boilers for mercury and CO_2. This is one of the main reasons that gasification is a better option..

Q. What Is Integrated Gasification Combined Cycle (IGCC)?

A. Integrated Gasification Combined Cycle (IGCC) is the efficient integration of the coal gasification process with the pre-combustion removal of pollutants and the generation of electricity using a combined cycle power plant. Due to the high pressure and low volume of the concentrated synthesis gas that is produced it is capable of higher levels of pollutant removal at lower costs than pulverized coal (PC) combustion.

Exhibit RCF-3 shows the various parts of an IGCC plant that will be described.

IGCC is a method of producing electricity from coal and other fuels. In an IGCC plant, coal is first converted to synthesis gas (also called syngas) composed primarily of hydrogen, carbon monoxide and carbon dioxide. After removing particulate matter, sulfur, mercury and other pollutants, the cleaned syngas is combusted in a combined-cycle power plant to produce electricity.

In the first step of the IGCC process, coal is slurried with either water or nitrogen and enters the gasifier. It is mixed with oxygen, not air, which is provided to the gasifier from an air separation unit. The coal is partially oxidized at high temperature and pressure to form syngas. The syngas leaves the gasifier, while the solids are removed from the bottom of the gasifier. The operating conditions in the gasifier vitrify the solids. In other words, the solids are encased in a glass-like substance that makes them less likely to leach into groundwater when disposed of in a landfill as compared to solid wastes from a conventional coal plant.

After leaving the gasifier, the syngas undergoes several clean-up operations. Particulate matter is removed. Next, a carbon bed can be used to take out mercury. Finally, sulfur (in the form of H2S) is removed from the syngas in a combination of steps that usually involve hydrolysis followed by an adsorption operation using MDEA (methyldiethanolamine) or Selexol. The

H2S that is removed from the syngas is converted into commercial-grade sulfur or sulfuric acid which are sold as byproducts.

The clean syngas enters a combustion turbine where it is burned to produce electricity. The heat from the exhaust gases is captured in a heat recovery steam generator (HRSG) and the resulting steam is used to produce more electricity. The combustion turbine, combined with the HRSG, is the same configuration commonly used for natural gas combined cycle (NGCC) plants. In Europe and Japan, some IGCC units have installed selective catalytic reduction (SCR) to control nitrous oxides (NO_x) emissions from the turbine, but in the United States, NO_x emissions at existing IGCC plants have been reduced with diluent injection only. The majority of recent final permits for IGCC plants in the U.S. have included SCR for lower NOx emissions. (Source: Air Construction/Prevention of Significant Deterioration Permit Application for Tampa Electric Polk Unit #6, prepared by Environmental Consulting & Technology, September 2007, Table 5-2).

Q: What are the Other Advantages of Using Gasification Plants?

A: Gasification, which is also called Partial Oxidation, can use a wide range of fuels and can produce a wide range of products as shown in Exhibit RCF-4.

The fuel flexibility of gasification is demonstrated by its ability to use all types of coal, petroleum coke, biomass, refinery wastes, and waste materials. The synthesis gas that is produced consists of mainly carbon monoxide (CO) and hydrogen (H2) which are used as the raw materials to produce (or synthesis) a wide range of chemicals. This synthesis gas can also be used as fuel directly for a combined cycle power plant called an IGCC (Integrated Gasification

Combined Cycle) plant. It can be further processed in a shift reactor to produce hydrogen and carbon dioxide (CO_2). The hydrogen can be used as a fuel or used to improve fuel quality in a refinery. The CO_2 can be used for enhanced oil recovery to produce addition oil from aging oil fields. This demonstrates the wide range of products that can be produced by gasification. The production of multiple products from a single plant is called polygeneration. Economic analyses have indicated that polygeneration of fuels, chemicals and electricity improves the profitability of gasification plants.

IV. COST OF ELECTRICITY FROM PULVERIZED COAL AND IGCC PLANTS (With and Without CO_2 Capture)

Q. What Do the Most Recent Studies Conclude About the Cost of Electricity from New IGCC Plants and New Pulverized Coal Plants?

A. The most recent and comprehensive studies on the costs of electricity from new IGCC plants and new PC plants are:

The Future of Coal, by the Massachusetts Institute of Technology (MIT), April 2007 and Cost and Performance Baseline for Fossil Energy Plants, by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL), May 15, 2007.

Exhibit RCF-5 is from the MIT Report The Future of Coal. This exhibit shows the relative cost of electricity (COE) from PC and IGCC plants both without and with CO2 capture. To validate their study the MIT report compared their results with the COE estimates from three other sources and summarized the results as shown in Exhibit RCF-5. This MIT exhibit uses the PC plant without CO2 capture as the reference case at a value of 1.0. This exhibit shows that MIT's COE from an IGCC plant is only 5% higher than the

COE from a PC plant. Therefore the significant emission reductions by using IGCC will only increase the cost of electricity production by 5%. It should be noted that this comparison is without CO2 capture and using Illinois #6 Bituminous coal for both cases. Exhibit RCF-5 also shows that when CO2 capture is considered, the COE produced by the PC plant is increased by 60% while the COE produced by the IGCC plant is only increased by 30%.

IGCC plants are capable of using lower cost fuels including petroleum coke (petcoke), biomass wastes and renewable energy crops. PC plants are limited to only small amounts of these lower cost fuels due to their combustion characteristics. The Cost of Electricity (COE) can be reduced significantly by utilizing lower cost fuels for the IGCC plants.

Q. Do Other Studies Confirm this Conclusion of Significantly Lower Costs for Capturing CO_2 in IGCC Plants than PC plants?

A: Yes.

Exhibit RCF-5 shows the results of studies performed by the Gasification Technology Council (GTC), American Electric Power (AEP) and General Electric (GE) which all show that IGCC plants will be more cost effective than PC plants when carbon reductions are required. IGCC plants are capable of capturing CO_2 at much lower costs than pulverized coal plants.

Exhibit RCF-6 is from the recent Department of Energy's (DOE) National Energy Technology Laboratory (NETL) report Cost and Performance Baseline for Fossil Energy Plants, May 15, 2007. This exhibit shows the levelized cost of electricity for IGCC, PC and natural gas combined cycle (NGCC) plants without and with CO2 capture and sequestration. The proposed AMPS-Ohio plant would be classified as Subcritical PC and this exhibit shows the COE without carbon capture and sequestration (w/o CCS) and with carbon capture and sequestration (w/ CCS).

This exhibit shows that without CCS the PC plants have the lowest COE. The disadvantages of these PC plants are their significantly higher emissions and much higher costs for CCS. Exhibit RCF-6 indicates that CO2 capture and storage will increase the cost of electricity by 85% for the AMPS-Ohio plant (Subcritical PC design). This same study indicates that CO2 capture and storage will increase the cost of electricity by 32% for an IGCC plant. This much higher cost for CO2 capture from the proposed AMPS-Ohio plant is a significant financial risk.

The capture, transport and injection of CO_2 is being doneon a commercial scale at the Great Plains Synfuels Plant which will be described in later testimony. CO2 capture from coal derived syngas is a commercially proven process that has been used for decades in gasification plants around the world. This technology can be applied to IGCC units to remove CO2 from the syngas prior to use in the combustion turbine.

No method of CO_2 capture is commercially available or economically viable for the proposed PC power plants. PC plants will have to capture the CO2 from the flue gas stream, which will require much larger and more expensive equipment to capture the CO2 than IGCC technology. Research & Development (R&D) has only started on technology that may be capable of capturing CO_2 from PC plants. It will take many years before these R&D projects determine if these new technologies are technically and economically feasible.

The Chilled Ammonia Process that is one of the proposed methods for capture of CO_2 from PC plants has been evaluated by DOE/NETL. (Source: <u>Chilled Ammonia-based Wet Scrubbing for Post-Combustion CO2 Capture,</u>

DOE/NETL-401/021507, February, 2007). NETL has already discontinued funding of future development of this process. NETL's testing and evaluations have indicated that this process is not capable of reaching the goals of technical and economic feasibility for commercial operation. For gasification plants the technology is already in commercial operation for CO_2 capture, transportation and injection.

Due to the future requirements to capture CO_2 and the more stringent emission limits for other emissions, the IGCC plants will be less expensive to operate in the future. The net result of selecting the IGCC plant, rather than a pulverized coal plant, is lower environmental impact now and lower cost electricity in the future.

Q: Have the Environmental and Health Costs Associated with the Emissions from Electric Generation been Determined for IGCC and PC Plants?

A: Yes.

Since the emissions from a PC plant are presently allowed to be significantly higher than an IGCC plant any economic analysis should include the environmental and health costs associated with these higher emissions.

Exhibit RCF-7 compares the economic impact associated with the higher emissions from PC plants than IGCC plants. Using published data on the environmental and health costs associated with the emissions of PM, SO_2 and NOx this table compares the economic costs for IGCC and PC plants for their current emission levels. Exhibit RCF-7 shows that when the costs for the higher emissions are included, the true cost of electricity is less for the IGCC plant.

Q. Have You Compared the Cost of Electricity Produced from a New IGCC Plant using Petroleum Coke with the Cost of Electricity from a New Pulverized Coal Plant using Bituminous Coal?

A. Yes.

I prepared Exhibit RCF-8 which shows that the costs of electricity for the three types of Pulverized Coal (PC) plants are higher than the cost of electricity for an IGCC plant using Petroleum Coke (PetCoke) in Florida. The Florida location was selected for comparison because of the proposed PC plants that were being planned in Florida and the availability of petcoke costs delivered to the commercial IGCC plant at Tampa Electric. Exhibit RCF-8 shows that although the IGCC plant has a higher capital cost than the PC plants it has a significantly lower fuel cost when using petcoke. Petroleum coke is the byproduct of a refinery process used to drive-off lighter hydrocarbons from heavy residual oil. Solid petroleum coke is what is left behind. The U.S. petroleum refineries produce over 43 million tons per year of fuel-grade petcoke that can be used by IGCC plants. This petcoke can provide over 17,000 MW of new generating capacity in the U.S. At the present time most of this petcoke is exported to other countries that allow the higher emissions of SO_2 that petcoke produces. The use of petcoke in PC plants is usually limited to a maximum of 20% petcoke due to combustion and emission limitations. However IGCC can use 100% petcoke and make use of this lower cost fuel. The average price of petcoke for the past 20 years has been about half of the cost of coal. IGCC plants can effectively remove the sulfur from petcoke and sell it as a valuable byproduct. Therefore an IGCC plant utilizing petcoke is a lower cost alternative to a pulverized coal plant. For the past 10 years Tampa Electric has been using petcoke in their 250 MW IGCC plant. Tampa Electric's President Chuck Black was recently quoted as saying: "it's our least cost-generating resource, so we count on it and use it every day as part of our system" in the November 2006 issue of Time Magazine, Inside Business.

Three companies have recently announced that they plan to build petcoke IGCC plants. These are the BP Carson IGCC plant in California, the Hunton IGCC plant in Texas and the TransCanada IGCC plant in Saskatchewan, Canada.

The sources of data for Exhibit RCF-8 - Cost of Electricity Comparison Chart for Florida are:

1. Capital, O&M and all non-fuel costs are based upon: Department of Energy/NETL Presentation, <u>Federal IGCC R&D: Coal's Pathway to the Future</u>, by Juli Klara, presented at GTC, Oct. 4, 2006.

2. Efficiencies and fuel consumption calculations are based upon: EPA Final Report, <u>Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies</u>, July 2006.

3. Fuel costs are based upon: Department of Energy, Energy Information Administration, <u>Average Delivered Cost of Coal and Petroleum Coke to Electric Utilities in Florida, 2005 and 2004</u>, and Tampa Electric Company's (TECO) data presented at plant tours of Polk Power Station's IGCC plant.

Q: Are Any Companies Planning to Use Petcoke With CO2 Capture and Sequestration?

A: Yes.

British Petroleum (BP) is proposing to build a 500 MW IGCC plant in the Los Angeles area that will use petroleum coke. This plant will also capture CO_2 and use the CO_2 in enhanced oil recovery (EOR) projects. Exhibit RCF-9 is a diagram of BP's IGCC project. Hunton Energy has announced a 1,200 MW IGCC project in the Houston area. The plant will use petroleum coke from a Valero refinery as fuel under a long-term supply agreement. Hunton Energy has stated the project will be designed to capture and sequester CO_2. The proposed TransCanada IGCC project will be a polygeneration facility, located in Belle Plaine, Saskatchewan, Canada, is expected to use petroleum coke as feedstock to produce hydrogen, nitrogen, steam and carbon dioxide for fertilizer production and enhanced oil recovery (EOR), and to generate approximately 300 MW of electricity. This project plans to capture and sequester over five million metric tons of carbon dioxide annually to increase local oil production.

V. AIR POLLUTANT EMISSIONS FROM PULVERIZED COAL AND IGCC PLANTS

Q: Are the Emissions from Pulverized Coal (PC) Plants Significantly Higher Than IGCC Plants? If So, Explain.

A: Yes.

Exhibit RCF-10 shows the much lower emissions that are produced from Integrated Gasification Combined Cycle (IGCC) plants than Super-critical Pulverized Coal (SCPC) plants. This exhibit is from an Electric Power Research Institute's (EPRI) presentation on June 28, 2006. It compares the emissions levels (in lb/MWh) that EPRI believes should be obtained by current state-of-the-art PC, IGCC and natural gas combined cycle (NGCC) plants . The SCPC plant design was chosen to represent the more efficient design for new PC plants. The AMPS – Ohio plant is being proposed with selective catalytic reduction (SCR) for NOx control. Therefore the relevant comparison from this exhibit will be the SCPC + SCR plant versus the IGCC + SCR plant. This EPRI chart indicates that for bituminous coal the IGCC plants will produce:

- 67% less NO_x
- 93% less SO_2
- 40% less soot or fine particulate (PM10)

The potential for future electric cost increases due to future environmental regulations is less for IGCC because IGCC plants can control all emissions more economically than PC plants.

Q: Do Other Recent Studies Show These Significant Differences in Emissions Between IGCC and PC Plants?

A: Yes.

Exhibit RCF-11 summarizes an EPA Report, Environmental Footprints and Costs of Coal-Based Integrated Combine Cycle and Pulverized Coal Technologies, US. Environmental Protection Agency, EPA-430/R-06/006, July 2006. This EPA report compares the emission levels (in lb/MMBtu) that EPA believes should be obtained by current state-of-the-art IGCC and PC plants. This report also demonstrates the lower emissions that are capable with IGCC plants.

Q: Do Recent IGCC Plants' Permit Levels and Proposed Permit Levels Confirm that these Significantly Lower Levels of Emissions can be Produced in Actual Plants?

A. Yes.

Exhibit RCF-12 shows a summary of emissions from recent IGCC permits and proposed permit levels. This table summarizes proposed emission levels from IGCC plants that have recently received or applied for air permits. The IGCC plants proposed in the last 12 months have sought to control sulfur using Selexol, a more effective control strategy than MDEA. These plants include, AEP in Ohio and West Virginia, Northwest Energy, Tondu, Duke, ERORA (Illinois and Kentucky). Selexol effectively removes sulfur levels to between 0.0117 to 0.019 lb/MMBtu heat input into the gasifier.

As this table shows, a majority of IGCC plants that have filed applications in the last 12 months include selective catalytic reduction (SCR) to control NOx. These include, Northwest Energy, Tondu, ERORA in Illinois and Kentucky, and Duke in Indiana The Duke plant includes SCR, but bases reductions on diluent injection only. Since the preparation of this table the Taylorville plant now has a final permit and Cash Creek has a draft permit. The NO_x emission rates for SCR controlled IGCC plants is 0.012 - 0.025 lb/MMBtu based upon heat into the gasifier.

These trends toward Selexol and SCR adoption are occurring faster than EPA predicted in its July 2006 report, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies. The July 2006 EPA report assumed that MDEA and diluent injection would be BACT for the near-term. This report was based upon a "snap shot" of IGCC permits that is out-of-date. As this table shows, the market has responded with technology faster than the EPA report anticipated.

In deciding which emission rates to compare to the AMPS-Ohio plant's proposed emission rates, the highest weight should be placed on recently proposed IGCC plants because they represent the most current view of IGCC permit levels. The least weight should be placed on existing IGCC plants and IGCC plants with permits issued prior to 2003 because they do not represent the capabilities of current IGCC technology.

Q. What are the Proposed Emission Rates from AMPS-Ohio Plant and How Do they Compare with Recent IGCC Permit Applications?

A. Exhibit RCF-13 summarizes the range of recently filed air permits for IGCC plants and compares them to the emission levels proposed in the draft air permit for the AMPS-Ohio plant. An IGCC plant would have significantly lower emissions of all pollutants than the proposed AMPS-Ohio.

Exhibit RCF-13 shows that:

An IGCC plant with the Selexol process would emit only 8% to 13% of the sulfur dioxide of the proposed AMPS-Ohio plant.

An IGCC plant with the SCR process would only emit 17% to 36% of the nitrogen oxides of the proposed AMPS-Ohio plant.

An IGCC plant would only emit 7% to 42% of the particulate mater of the proposed AMP-Ohio plant.

An IGCC plant would only emit 10% to 29% of the mercury of the proposed AMPS-Ohio plant.

An IGCC plant would also be expected to emit about three-quarters less CO and significantly less sulfuric acid mist and VOCs than the proposed AMPS-Ohio plant.

Q. What are the Total Tons per Year of Pollutant Emissions from the AMPS-Ohio Plant and How Do they Compare with Recent IGCC Permit Applications?

A. Exhibit RCF-14 is a comparison of the total tons per year of pollutants that the AMPS-Ohio plant (two 480 MW units = 960 MW) would emit under the Ohio EPA draft air permit and the emissions that a similarly sized IGCC plant (three 320 MW units = 960 MW) would emit, based on the final permit for the Taylorville IGCC plant in Illinois. This chart shows the significantly lower emissions of all pollutants for the Taylorville IGCC plant than the proposed AMPS-Ohio PC plant.

Exhibit RCF-14 shows that:

The Taylorville IGCC plant will only emit 35% of the nitrogen oxides of the proposed AMPS-Ohio plant.

The Taylorville IGCC plant will only emit 10% of the sulfur dioxide of the proposed AMPS-Ohio plant.

The Taylorville IGCC plant will only emit 54% of the particulate mater of the proposed AMP-Ohio plant.

The Taylorville IGCC plant will only be allowed to emit 66% of the mercury of the proposed AMPS-Ohio plant but the permit application filed for the Taylorville IGCC plant indicated that only 10% of the mercury of the proposed AMPS-Ohio plant would be emitted. The final permit also indicated that 95% mercury capture would be required.

The Taylorville IGCC plant will only emit 34% of the sulfuric acid mist of the proposed AMPS-Ohio plant.

The Taylorville IGCC plant will only emit 22% of the carbon monoxide of the proposed AMPS-Ohio plant.

The Taylorville IGCC plant will only emit 30% of the volatile organic compounds of the proposed AMPS-Ohio plant.

Q: What are the Proposed Emission Rates from AMPS-Ohio Plant and How Do they Compare with Recent PC Permit Applications?

A:

Exhibit RCF-15 compares the proposed permit emission rates of the AMPS-Ohio plant with two other recently proposed PC plants. These plants were selected for comparison because they will be utilizing the same types of coals and the same types of emission control systems as the AMPS-Ohio plant.

Exhibit RCF-15 shows that:

These proposed PC plants will only emit 71% of the nitrogen oxides of the proposed AMPS-Ohio plant.

These proposed PC plants will only emit 27% of the sulfur dioxide of the proposed AMPS-Ohio plant.

These proposed PC plants will only emit 87% of the particulate mater of the proposed AMP-Ohio plant.

These proposed PC plants will only emit 47% and 63% of the mercury of the proposed AMPS-Ohio plant.

VI. TAMPA ELECTRIC COMPANY (TECO) AND IGCC

Q. How Long have Commercial Size IGCC Plants been in Operation in the U.S.?

A. Commercial IGCC plants have been in operation for more than 10 years in the U.S.

Exhibit RCF-16 shows the Polk Power Plant near Tampa, FL which is a greenfield site and the Wabash Power Plant in Indiana which is a conversion of an existing plant.

Tampa Electric Company's (TECO) Polk Power Station began operation in 1996. It produces 250 MW (net) of electricity. It uses a Texaco (now GE) oxygen-blown gasification system. Power comes from a GE 107FA combined cycle system. During the summer peak power months, availability is greater than 90 percent when using back-up fuel.

The Wabash River Coal Gasification Repowering Project in Indiana began operation in November 1995. It demonstrated the repowering of an existing coal plant to IGCC. The plant uses an "E-Gas" oxygen-blown gasification system which is sold by ConocoPhillips.

For larger size plants, multiple units are being proposed which will improve system availability and reduce costs by making use of standard, modular designs.

Q. Have the Utilities Involved with these IGCC Plants Announced Plans to Build Other IGCC Plant?

A. Yes.

Tampa Electric Company had announced that they would build an additional 630 MW IGCC plant at the Polk Power Plant for operation in 2013. Tampa Electric started operation of its existing 315 MW(gross)/250MW(net) IGCC plant in October, 1996 and has recently celebrated its 10th year anniversary. It is the lowest cost plant to operate on Tampa Electric's System and has won numerous environmental awards.

Cinergy was the utility partner that was part of the Wabash IGCC plant. Cinergy has now merged with Duke Energy. Duke Energy has announced that they will build a 630 MW IGCC plant to be built at their Edwardsport Generating Station in Edwardsport, Indiana.

The Nuon Utility in the Netherlands, Belgium and Germany has been successfully operating an IGCC plant on coal and biomass for the past 12 years at about 253 MW. Nuon recently announced that they are building a 1200 MW plant which will consist of four 300 MW units.

There are 33 IGCC plants being planned in the United States by utilities and independent power producers. (Source: Tracking New Coal-Fired Power Plants, by DOE/NETL,October 10, 2007 page 13, www.netl.doe.gov/coal/refshelf/ncp.pdf)

Q: Has Tampa Electric Recently Deferred their New IGCC Plant?

A: Yes. On October 4, 2007 Tampa Electric published a Press Release with the following statements:

"TAMPA ELECTRIC DEFERS USE OF CLEAN COAL GENERATING UNIT BEYOND 2013 NEEDS

Company cites financial risk to customers, shareholders from uncertain carbon requirements

Tampa, Florida – October 4, 2007 – Tampa Electric today announced that it no longer plans to meet its 2013 need for baseload generation through the use of integrated gasification combined cycle technology, or IGCC. Primary drivers of the decision announced today include continued uncertainty related to carbon dioxide (CO_2) regulations, particularly capture and sequestration issues, and the potential for related project cost increases. Because of the economic risk of these factors to customers and investors, the company believes it should not proceed with an IGCC project at this time.

The company remains steadfast in its support of IGCC as a critical component of future fuel diversity in Florida and the nation, and believes the technology is the most environmentally responsible way to utilize coal, an affordable, abundant and domestically produced fuel. Tampa Electric is recognized as the world leader in the production of electricity from IGCC. The company also believes that IGCC technology offers the best platform to capture and then sequester CO_2. Once public policy issues regarding long-term sequestration are resolved, demonstration projects can be conducted that will lead to a better understanding of the science, technologies and economics of sequestration."

Q: Has Nuon Recently Announced the Phased Construction of their New IGCC Plant?

A: Yes.

Nuon recently announced that due to significant construction cost increases for all major projects and the longer schedule for some major equipment they now have a two phase construction schedule to build the combined cycle part in phase 1 and the gasification part in phase 2.

Q: Are Tampa Electric and Nuon confident in the technical feasibility and significant environmental performance of IGCC plants?

A: Yes.

The announcements from Tampa Electric about their deferral and Nuon about their phased construction both indicated their confidence in the IGCC technology and its significant environmental performance. The primary reasons for Tampa Electric's decision are uncertainty related to carbon dioxide (CO_2) regulations, particularly capture and sequestration issues, and the potential for related project cost increases. The primary reasons for Nuon's decision is project cost increases and scheduling for some major equipment.

VII. REFERENCES TO CONTACT FOR PC AND IGCC PLANTS

Q. What Government Officials and Power Plant Managers are the Most Informed about the Advantages and Disadvantages of Using PC and IGCC Technologies for New Power Plants?

A. Exhibit RCF-17 shows references that I recommend to be contacted prior to anyone making a decision on which technology to use for a new power plant. Each of them have agreed to be contacted to provide their advise concerning their decision process in evaluating PC and IGCC plants.

VIII. COMMERCIALLY OPERATING AND PLANNED IGCC PLANTS

Q. Please Describe the Types and Number of Commercially Operating Gasification Plants.

A. Exhibit RCF-18 shows the results of the 2004 world survey of operating gasification plants prepared by the Gasification Technologies Council for the Department of Energy.

Gasification dates back to the 18th century, when "town gas" was produced using fairly simple coal-based gasification plants. But what we think of as modern gasification technology dates back to the 1930's when gasification was developed for chemicals and fuels production. Today (2007), there are around 130 gasification plants worldwide that produce fertilizers, fuels, steam, hydrogen and other chemicals, and electricity. Of these 130 plants, seventeen are IGCC plants.

Q. How Many Commercially Operating IGCC Plants Are There?

A. Exhibit RCF-19 shows seventeen (17) commercially operating IGCC plants. Together, these plants have a capacity of 3,872 MW(net) and have almost one million hours of operation on syngas. These plants use a variety of fuels including coal, petroleum coke, biomass, and refinery residues.

Four IGCC plants tend to be the focus of utility interest because they were designed to use coal: 1) Wabash, Indiana, 2) Polk, Florida, 3) Nuon, Netherlands, and 4) Elcogas, Spain. These four commercial IGCC plants have been operating from 10 to 13 years. They have successfully integrated the gasification process with the combined cycle power plant to enable more efficient use of coal while significantly reducing emissions. These plants range in size from 250 to 320 MW per unit.

A second set of plants built after Wabash, Polk, Nuon, and Elcogas are also important in the progression of IGCC. These plants operate at refineries in Italy. They are: Sarlux 545 MW, Sardinia; ISAB Energy 510 MW, Sicily; Api Energia 280 MW, Falconara; and Eni Power 250 MW, Ferrera. The first two demonstrate that IGCC plants can be built at a scale above 500 MW. Three of the plants were built using non-recourse project financing provided by over 60 banks and other lending institutions. They show that IGCC can be a commercially bankable technology.

Both the Salux and ISAB Energy plants use more than one gasification "train" and operate with more than 90 percent availability without a spare gasifier. The Italian experience with IGCC, while using refinery residues as fuel, is relevant to discussions of coal-fired or petcoke-fired IGCC, because essentially the same equipment is utilized in both instances, differing only in the feed preparation and how solids are removed.

The first commercial-scale demonstration IGCC plant in the United States was Southern California Edison's Cool Water Plant located at Barstow, California. It operated between 1984 and 1989. The plant successfully utilized a variety of coals, both subbituminous and bituminous, and had a feed of about 1,200 tons/day. The project used an oxygen-blown Texaco gasifier with full heat recovery using both radiant and convective syngas coolers.

Q. What is the Status of IGCC Projects and Gasification Projects being Developed in the North America?

A. Exhibits RCF-20, 21 and 22 show 57 of the publicly announced IGCC and gasification projects being developed in North America.

The range of IGCC projects under development in the United States includes proposals that would be fueled with petroleum coke, bituminous coal, subbituminous coal, and lignite.

A DOE Report lists 33 IGCC projects that are planned in the U.S. by utilities and independent power producers. This Department of Energy Report is Tracking New Coal-Fired Power Plants, by Eric Shuster, October 10, 2007, page 13 (Source: http://www.netl.doe.gov/coal/refshelf/ncp.pdf).

IGCC technology is commercially available from five major companies: GE, ConocoPhillips, Siemens, Shell and Mitsubishi Heavy Industries (MHI). The gasification industry has undergone many changes in the past few years that have given confidence to industry and lenders that IGCC can obtain sufficient performance warranties to build new IGCC plants. GE, a major company in the power field, has purchased ChevronTexaco's gasification business, and has partnered with Bechtel to offer fully warranted IGCC plants. ConocoPhillips has purchased the E-Gas technology from Global Energy. Siemens has purchased the German gasification technology formerly offered by Future Energy. Shell has partnered with Udhe and Black and Veatch.

Q. What is the Status of IGCC and Gasification Projects that are Presently Under Development Outside of North America?

A. Exhibits RCF-23 and 24 are a recent list that shows 26 of the IGCC and gasification projects that are being developed outside of North America.

IX. CARBON CAPTURE AND SEQUESTRATION (CCS)

Q: What is the Status of Proposed Power Plants with Carbon Capture & Sequestration?

A: Exhibit RCF-25 shows the proposed power projects above 275 MW that are being designed for CO2 capture and storage. The large majority of these projects will be using gasification and precombustion removal of CO2. This is due to the availability of proven commercial capture technology.

Q: Are Carbon Capture Technologies for PC Plants Commercially Available?

A: No.

Carbon capture technologies for PC plants are <u>not</u> commercially available. The MIT Report extrapolated the cost and performance for post-combustion capture of carbon dioxide from PC plants based on a very limited set of engineering data. Comparisons of this extrapolated data versus the commercial data that is available for CO2 capture from gasification plants obscures the fact that CO2 capture from PC plants are <u>not</u> close to commercial availability. Neither the amine or aqueous ammonia systems for CO2 capture at PC plants nor oxyfuel firing are close to commercial availability. Significant additional scale-up, improvements and testing are required for each of these technologies. The aqueous ammonia technology has been tested at the laboratory scale by DOE/NETL (Source: <u>Ammonia-based Process for Multicomponent Removal from Flue Gas</u>", R&D Facts, DOE/NETL, September, 2007) and a 1 MW slipstream pilot plant is being planned. Oxyfuel combustion of pulverized coal is in its infancy, with the largest unit in operation a mere 1.5 MW (thermal) test facility in Alliance, Ohio (Source: <u>State of the Art</u>

of Oxy-Coal Combustion Technology for CO2 Control from Coal-Fired Boilers, by Farzan, H, et al, Babcock & Wilcox Technical Paper presented to Third International Conference on Clean Coal Technologies for Our Future, May 2007).

While these technologies should certainly be the subject of continued research, they are not likely to present real opportunities for carbon capture from coal use in the near term and should not be used at this time to justify the construction of new pulverized coal plants.

Other technologies for post-combustion capture of CO2 from PC plants have been discussed but at present those technologies remain speculative and appear to present significant environmental and/or economic challenges (e.g., chilled ammonia).

Q: **Are Carbon Capture Technologies for IGCC Plants Commercially Available?**

A: Yes.

Carbon capture technology for IGCC is commercially available and proven. In contrast to no commercial carbon capture technology for PC plants, IGCC plants carbon capture is considered a proven and commercially available technology. The necessary components of a carbon capture system for IGCC (water-gas shift reactors, acid gas removal systems, and CO2 compression) have been demonstrated at numerous facilities around the world, including the Great Plains Synfuels plant in North Dakota where 1 million tons of CO2 per year is captured from the gasification of lignite coal and used for EOR in Canada (Sources: The New Synfuels Energy Pioneers by Stan Stelter, Introduction by Former President Jimmy Carter, published by Dakota Gasification Co.- 2001, A subsidiary of Basin Electric Power Cooperative; and Experience Gasifying ND Lignite, by Al Lukes, Dakota Gasification Company, The Great Plains Synfuels Plant, presented at the Montana Energy Future Symposium).

While no existing IGCC plant captures carbon dioxide, industry confidence in the technology is very high. In recent testimony before the Florida Public Service Commission, Tampa Electric described the state of carbon capture equipment from IGCC in these terms: **"CO2 capture from syngas is a commercially proven process that has been used for decades around the world"** (Source:: Tampa Electric's Petition to Determine Need for Polk Power Plant Unit 6, Testimony of Mark J. Hornick, submitted to the Florida Public Service Commission on July 20, 2007).

X. SIZE AND AVAILABILITY OF NEW IGCC PLANTS

Q. Is it Possible to Build Large Size IGCC Plants?

A. Yes.

Large size plants are being built using modular designs that improve system reliability, increase efficiencies and provide fuel flexibility.

The Nuon Utility in the Netherlands, Belgium and Germany has been successfully operating an IGCC plant on coal and biomass for the past 12 years at about 253 MW. Nuon recently announced that they are building a 1200 MW plant which will consist of four 300 MW units. This design shown in Exhibit RCF-26 requires no additional scale-up from the design of their existing plant and makes use of readily available combined-cycle plants that have been used with natural gas. This modular design provides additional system reliability, increased efficiencies, fuel flexibility and any possible size.

The standard IGCC unit is now 300 MW. Most manufacturers are supplying 600 MW plants which consist of two 300 MW units. This is due to the fact that the gasifiers have been sized to produce the amount of synthesis gas needed for the 300 MW combined-cycle plants that are already in-service using natural gas. Therefore the 600 MW units that are being engineered consists of two units the same size as the existing units that have been operating for the past 10 years. Therefore there is no additional scale-up required. Any large size plant can be built by using additional 300 MW units. Three manufacturers have 300 MW IGCC units that have been operating successfully for the last 10 to 13 years. GE states that "IGCC technology can satisfy output requirements from 10 MW to more than 1500 MW, and can be applied in almost any new or repowering project where solid and heavy fuels are available." (Source: www.gepower.com/prod_serv/products/gas_turbines_cc/en/igcc/index)

Q. Have Recent Coal Gasification Plants and IGCC Plants Demonstrated Reliabilities Above 90% Required by the Utility Industry?

A. Yes.

A recent Gas Turbine World article reported on the capacity factors of the more recently built IGCC plants in Italy that utilize refinery waste such as asphalt as a fuel. As the report notes, the availability of these plants are between 90% and 94%. (Source: Refinery IGCC plants are exceeding 90% capacity factor after 3 years, by Harry Jaeger, Gas Turbine World, January-February 2006.)

Now GE offers to take on responsibility for everything "From Coal off the Coal Pile to Electrons on the Grid" by Ed Lowe, GE General Manager of Gasification (Source: Inside Business, Time Magazine, November, 2006.)

An additional advantage of an IGCC plant is that it can operate on various fuels. If the gasifier is out-of service for maintenance the power plant can still operate on natural gas or diesel fuel. This is not possible with a PC plant which is only designed for coal. Older IGCC plants built in the early 1990s such as Polk and Wabash that operate without a spare gasifier have demonstrated availabilities above 85%.

Major vendors of IGCC plants such as GE, Shell and ConocoPhillips will warrant that new IGCC plants will achieve greater than 90% availability with a spare gasifier. The economic comparisons conducted for Tampa Electric's IGCC plant indicate that it is more cost effective to operate on natural gas or diesel fuel than to build a spare gasifier to increase plant availability. Tampa Electric's IGCC plant has demonstrated reliability to produce electricity of 95% with their dual fuel capability. This is greater than PC plants that do not have dual fuel capability. (Source: <u>Tampa Electric's Presentation of Operating Results</u>, by Mark Hornick, Plant Manager, presented during plant tours.)

Therefore IGCC plants are being built without a spare gasifier. They will be able to operate above 90% availability by using their back-up fuel of either natural gas or diesel.

Reliability and availability are measures of the time a plant is capable of producing electricity. Reliability takes into account the amount of time when a plant is not capable of producing electricity because of unplanned outages. Availability takes into account the time when a plant is not capable of producing electricity because of planned and unplanned outages.

XI. THE GREAT PLAINS SYNFUELS PLANT

Q. Are There Any Commercially Operating Gasification Plants That Are Capturing CO_2?

A. Yes.

Exhibit RCF-27 shows the Great Plains Synfuels Plant in Beulah, North Dakota which is a good example of a commercial gasification plant. It began operating in 1984 and today produces more than 54 billion cubic feet of Synthetic Natural Gas (SNG) from 6 million tons of coal per year. If the SNG from this one plant were used in combined-cycle power plants there would be enough fuel for more than 1,000MW of generating capacity.

Adjacent to the Great Plains Synfuels Plant is the Antelope Valley Station which consists of two 440 MW lignite coal power plants that also started operation on lignite in the early 1980s.

Both plants are owned by the Basin Electric Power Cooperative. Al Lukes, Senior Vice President and COO of the Dakota Gasification Company, presented a paper at the 2005 Gasification Technologies Conference entitled Experience with Gasifying Low Rank Coals which showed the significantly lower emissions from the coal gasification plant than the coal-fired power plant. I recently asked Al Lukes which technology he would select today for a power plant, and he said "definitely the gasification technology".

Q. Has the Great Plains Synfuels Plant been Able to Commercially Demonstrate that the CO_2 from this Coal Gasification Plant can be Economically Captured and Injected?

A. Yes.

Carbon dioxide capture, transportation and injection has been operating commercially since 2000 at the Great Plains Synfuels Plant. In 2000, the Great Plains Synfuels Plant added a CO_2 recovery process to capture the CO_2. It transports the CO_2 by pipeline 205 miles, as shown in Exhibit RCF-28, to the Weyburn oil fields where it is used for enhanced oil recovery (EOR). In this way, the CO_2 does not become a global warming emission source but is sold as a useful byproduct to recover additional oil from depleted oil fields. Monitoring of the injected CO_2 has shown that this injection is effectively containing the CO_2 underground, although there are not specific standards in place addressing criteria for long-term sequestration. This CO_2 recovery process is expected to help extract 130 million extra barrels of oil from this oil field. This demonstrates the ability to efficiently capture and inject the CO2 from the gasification process.

XII. WATER CONSUMPTION FOR PC AND IGCC PLANTS

Q. Do IGCC Plants Use Less Water than PC Plant?

A. Yes.

Exhibit RCF-29 shows that an IGCC plant without carbon capture & sequestration (w/o CCS) uses 4,003 gpm of raw water versus the proposed sub-critical PC plant design proposed for AMPS-Ohio plant which will consume 6,212 gpm. This DOE/NETL Report shows that the proposed design for the AMPS-Ohio plants will consume 55% more water than the same size IGCC plant.

Exhibit RCF-29 also shows that an IGCC plant with carbon capture & sequestration (w/ CCS) uses 4,579 gpm of raw water versus the proposed sub-critical PC plant design proposed for AMPS-Ohio plant which will consume 14,098 gpm. This DOE/NETL Report shows that the proposed design for the

AMPS-Ohio plants will consume 200% more water than the same size IGCC plant. These are significant additional financial and environmental risks caused by the the proposed PC plants.

After considering the available technologies and the nature and economics of the various alternatives, the proposed AMPS-Ohio PC plants do not incorporate the maximum feasible water conservation practices.

The lower water usage for an IGCC plant w/o CCS is due mostly to the fact that a combined cycle power plant is being used which requires less cooling tower water. A combined cycle power plant consists of both a gas turbine and a steam turbine for power generation. The gas turbine portion of the power generation cycle does not require the large quantities of water for cooling that are needed for the steam turbine cycle. Since a PC plant generates all of its electricity from the steam turbine cycle it requires larger amounts of water.

Combined cycle plants are more energy efficient but require a clean fuel such as natural gas, diesel, or synthesis gas. The older, less efficient technology uses only a steam turbine, which must be used for PC plants due to the contaminants in the combustion products.

XIII. THE BENEFITS OF FUEL FLEXIBILIY FOR POWER PLANTS

Q: What are the Benefits of a Power Plant being Able to Use Different Fuels?

A: The 1200 MW IGCC Plant to be built by the Nuon Utility in The Netherlands is a good example of a multi-fuel power plant. This plant is shown in Exhibit RCF-26. It will have the capability of using coal, petcoke, biomass and natural gas. This plant will be able to respond to changing fuel prices and availability of these alternative fuels. The coal, petcoke and biomass can all be gasified to produce syngas for the combined-cycle power plants.

The biomass capability enables IGCC plants to use various renewable energy sources that will reduce the emissions of CO_2. Initially available biomass can be used as a lower cost fuel and then renewable energy crops can be developed as a new industry.

Adisadvantage of PC plants is that they are only capable of using coal. Therefore PC plants can not respond to changing market conditions and changing emission standards without significant increases in costs.

XIV. POWER PLANT EFFICIENCY

Q: What is the Heat Rate and the Efficiency of the Proposed AMPGS?

A: Neither the heat rate nor the efficiency of the proposed AMPGS are provided but can be calculated from the fuel input (5,191 million Btu per hour) provided on page 216 of the Draft Permit and from the electrical output (480 MW per unit) provided on page 1 of the Application for Need. From these two numbers the calculated heat rate and efficiency for the AMPGS are:

Heat Rate = 10,814 Btu per Kwh

Efficiency = 31.56 %

Although it is not stated in the Application for Need or the Draft Permit, it can be assumed from this heat rate and efficiency that the AMPGS will be using a sub-critical PC plant design.

Q: How Does the Heat Rate and Efficiency of the AMPGS Compare with Other PC Plant Designs?

A: Exhibit RCF-30 shows the various PC plant designs including sub-critical, super-critical and ultra-supercritical. These classifications are based upon the steam conditions that can be produced in these PC plants. The higher the temperature and pressure of steam that can be produced then the higher the efficiency of the plant. Higher efficiency plants will require less fuel and have a lower heat rate. The amount of fuel used is directly proportional to its heat rate and inversely proportional to its efficiency . Therefore a 38% efficient super-critical PC plant will use **20% less fuel** than a 31.56% efficient sub-critical PC plant.

The higher efficiency and lower heat rate is very important for two reasons. The less fuel used the lower the cost of electricity and the lower the emissions per Kwh of electricity produced. The current emission regulations are based upon pounds of pollutants emitted per Btu of heat input into the boiler. Therefore appropriate credit is not currently given for the higher efficiency of some power plant designs. EPA is in the process of changing their regulations from being based upon a heat input basis to being based upon an electricity output basis. This will then give appropriate credit to power plants with improved efficiencies.

Q: Have Other Studies Recognized the Importance of Power Plant Efficiencies?

A: Yes.

The Executive Summary from <u>The Future of Coal</u>, by the Massachusetts Institute of Technology (MIT), April 2007, page xiv, states: **"recommending that new coal units should be built with the highest efficiency that is economically justifiable"**

Q: Does the Higher Capital Cost of the Super-critical PC Plants Increase the Cost of Electricity by More than its Fuel Cost Savings?

A: No.

Both the M.I.T. Report and the DOE/NETL Study show that the Cost of Electricity (COE) is less for the Super-critical PC plant than the Sub-critical PC plant.

This proves that for PC plants the higher efficiency can be economically justified. Therefore AMPGS should not be specifying low efficiency PC plants since this will increase the costs of electricity and increase the emissions.

Q: Are the Higher Efficiency Super-critical Plants as Reliable as the Lower Efficiency Sub-critical Plants?

A: Yes.

Exhibit RCF-31 shows that the reliability is comparable for sub-critical and super-critical PC plants. This comparison is for a significant number of units within the same size range and from comparable ages of plants.

Q: Are Super-critical PC Plants Being Constructed by Most of the Major Equipment Manufacturers?

A: Yes.

Exhibit RCF-32 lists the various original equipment manufacturers and a sample of some of the super-critical plants that they have provided with the steam conditions for these plants.

RICHARD C. FURMAN
CONSULTING ENGINEER

Address: 10404 S.W. 128 Terrace, Miami, Florida 33176
Date of Birth: January 7, 1947
Height: 6'0" **Weight:** 170 lbs.
Marital Status: Married: 2 children
Phone #: (305) 232-4074 office; (305)439-5604 cell.
E-mail: RcFurman2@aol.com

<u>Education:</u> Massachusetts Institute of Technology, MS CHE 1972.
Worcester Polytechnic Institute, BS CHE 1969.

<u>Experience:</u>

February 2003 to Present

Retired – Volunteer at Camp Sunshine to help children with cancer and volunteer for the Clean Air Task Force (CATF), the Natural Resources Defense Council (NRDC), Environmental Defense, Sierra Club and Public Citizen to advise utilities, government agencies and the public about the environmental benefits, economic potential and energy security of using coal gasification technologies to produce electricity, fuels and chemicals .
Provided expert testimony and information on new energy technologies to Florida's Public Service Commission, Texas Senate Committee on Natural Resources and Georgia's Public Service Commission.

September 1989 - February 2003

Consulting Engineer – New Energy Technologies

Consulting engineer to various utility companies, equipment manufacturers, government agencies and environmental organizations on the development and application of new energy technologies.
Consultant in the areas of coal gasification, integrated gasification combined-cycle (IGCC) power plants, alternative fuels, cogeneration and natural gas cooling technologies.
Identify potential applications for these new technologies with electric and gas utilities. Introduce these new technologies to company executives, government officials and potential users. Assist engineers with designs and applications for these new technologies. Create marketing programs with manufacturers for increased use of these technologies.
Direct technical feasibility studies and financial analyses for site specific applications. Assist equipment manufacturers, the Electric Power Research Institute (EPRI), the Gas Research Institute (GRI), and the American Gas Cooling Center (AGCC) with development and demonstration of these new technologies.
Provided expert testimony and information on new energy technologies to Brazil's Center for Gas Technology and Trinidad's National Gas Company.

August 1981 - August 1989

Consulting Engineer – New Fuel Technologies

Consultant to various companies on the technical feasibility and business development for new fuel technologies. Major areas of consulting consist of the development and use of alternative new fuels and the conversion of power plants to these new fuels. Director and project manager for various development programs, feasibility studies, financial analyses, R&D projects, marketing analyses and commercialization of these new fuel technologies.

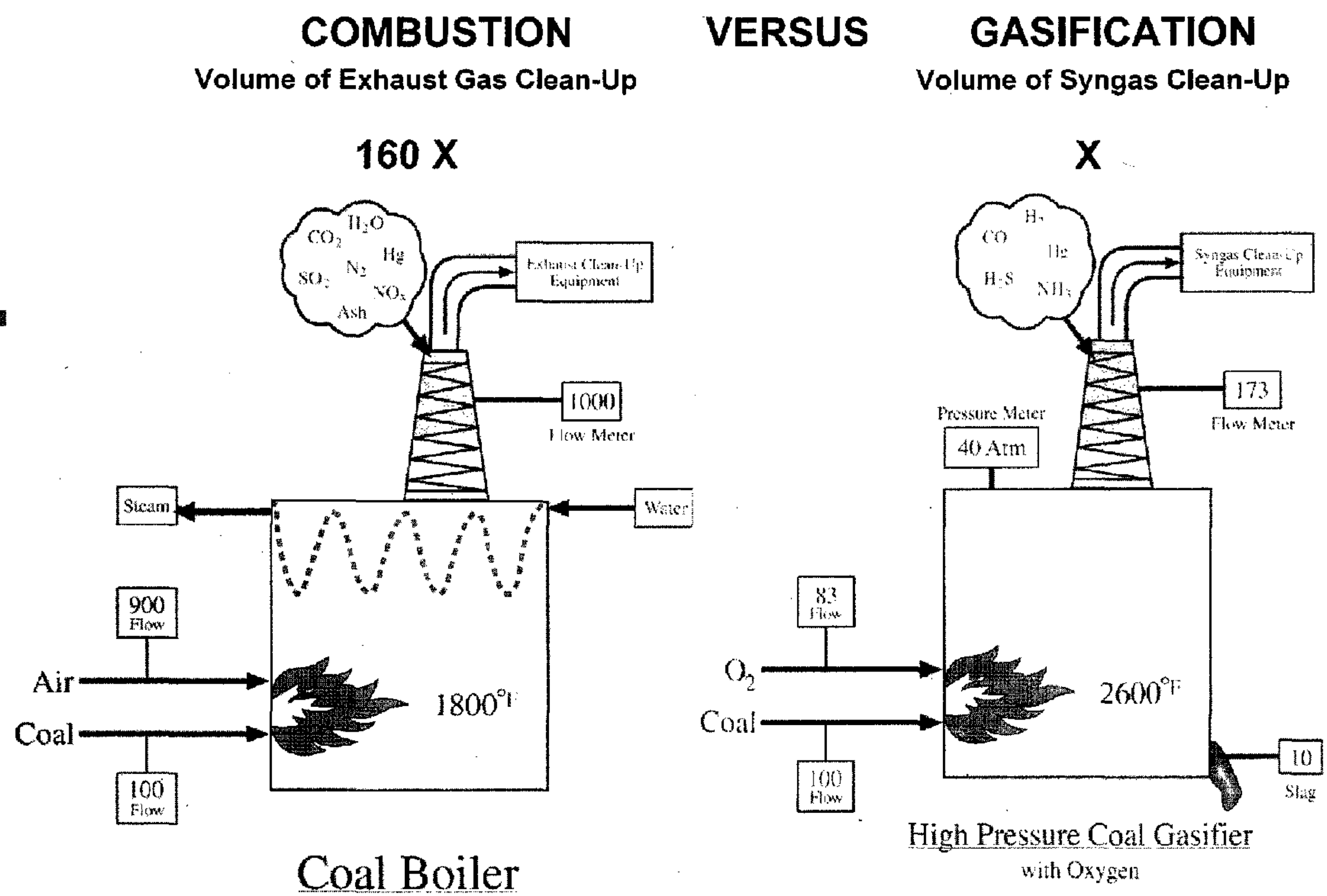
April 1977 - July 1981	Florida Power & Light Company, Miami, Florida Senior Project Coordinator – Research and Development Managed FPL's coal conversion program and fuels R&D program. Developed R&D projects with emphasis on alternative fuels and processes for electric power generation. Assessed the technical and economic feasibility of coal gasification, advanced coal cleaning technologies, coal-oil mixture technologies, coal-water slurry technologies, coal liquefaction processes, fluidized combustion processes and advanced pollution control methods. Established company R&D projects in uranium recovery, coal cleaning, coal-oil mixtures, coal-water slurries and combustion modifications.
September 1975 - March 1977	Center for Energy Policy, Inc., Boston, Massachusetts Program Manager Organized multi-disciplinary studies on the technical and economic feasibility of power plant conversions from oil to coal, the pricing policies for fuels and electricity and future methods for energy conservation in space heating. Directed engineering study for the conversion of New England Electric's Brayton Point Plant from oil to coal.
May 1972 - September 1975	Walden Research Division of ABCOR, Inc. Cambridge, Mass. Senior Engineer Industrial consultant for air pollution control, energy conservation, and industrial hygiene. Engaged in process modifications to reduce energy consumption. Responsible for engineering evaluations of air pollution control systems.
September 1970 - June 1972	Massachusetts Institute of Technology, Cambridge, Mass. Graduate Student, Teaching Assistant, Researcher Researcher – NSF grant to evaluate future energy sources and their environmental impact. Researcher for book entitled "New Energy Technology," by Hottel and Howard, MIT Press. Graduate Student – Master's thesis: "Technical and Economic Evaluation of Coal Gasification Processes." Teaching Assistant – "Principles of Combustion and Air Pollution" and "Seminar in Air Pollution."
June 1969 - February 1970	Southern California Edison Company, Los Angeles, California Chemical Engineer Engaged in power plant combustion air pollution control. Investigated two-stage combustion to reduce nitrogen oxides emission.

Professional Organizations

Electric Power Research Institute - EPRI
Gas Research Institute - GRI
Association of Energy Engineers - AEE
Cogeneration Institute - CI
American Institute of Chemical Engineers – AIChE
American Gas Cooling Center – AGCC

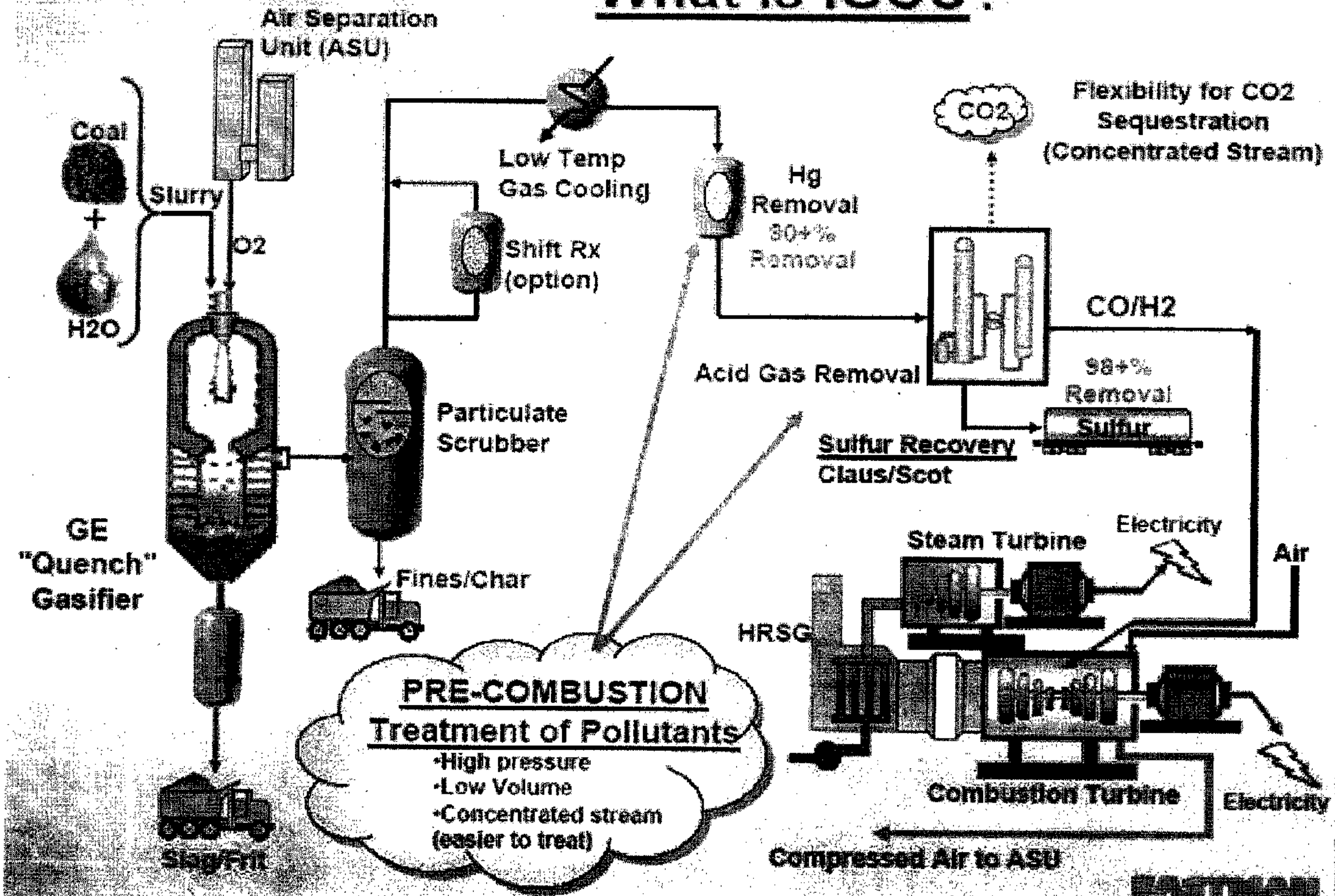
Exhibit RCF-1 Richard C. Furman Resume

COMBUSTION VERSUS GASIFICATION



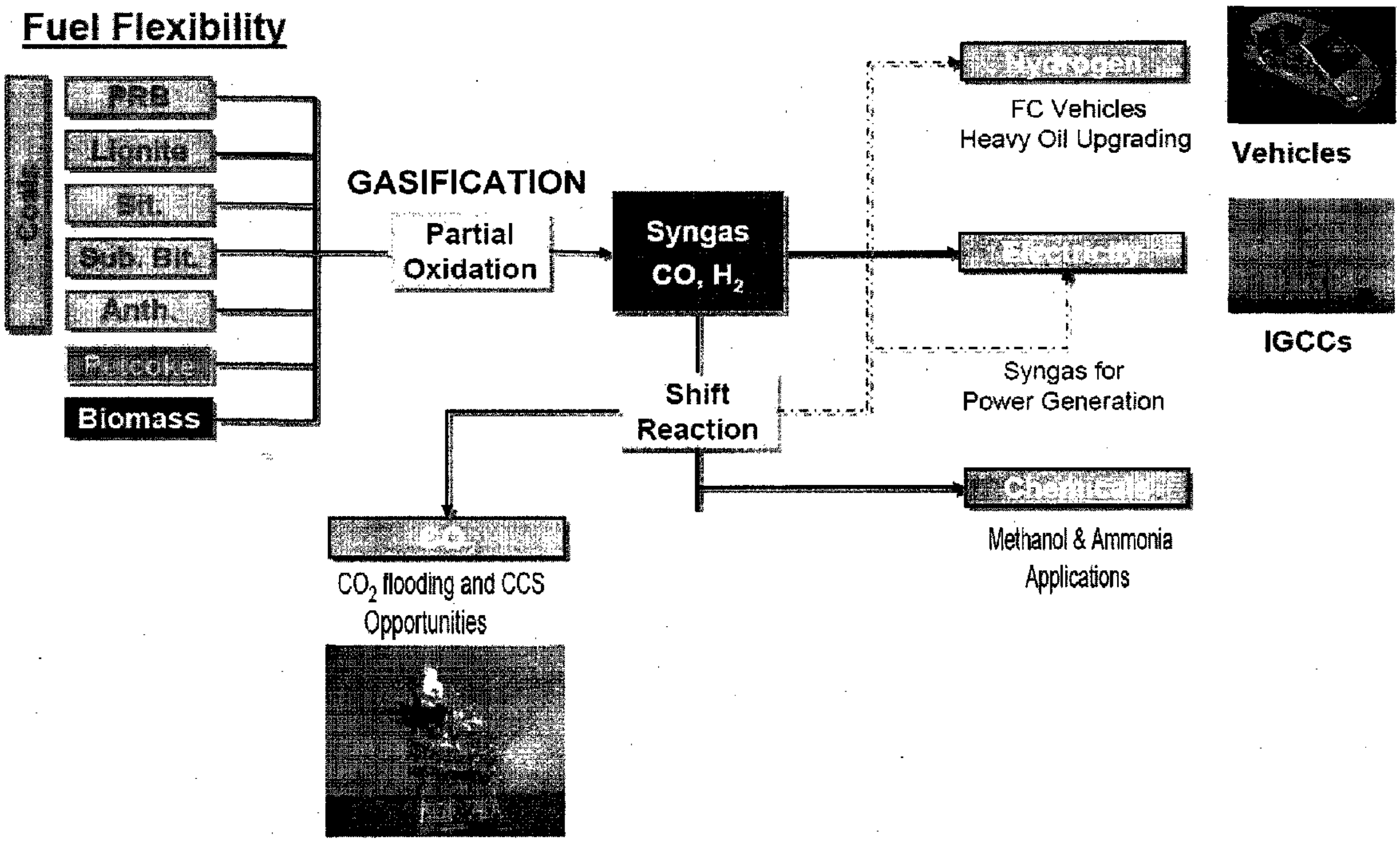
- (Source: EPRI Presentation – "Gasification Combined Cycles 101" by Dr. Jeffrey Phillips, pages 9 and 12, presented at the Workshop on Gasification Technologies, Tampa, FL 3/2/06)

What is IGCC?



Air Separation Unit (ASU)
Coal
H2O
Slurry
O2
GE "Quench" Gasifier
Slag/Frit
Particulate Scrubber
Fines/Char
Shift Rx (option)
Low Temp Gas Cooling
Hg Removal
90+% Removal
Acid Gas Removal
CO2
Flexibility for CO2 Sequestration (Concentrated Stream)
CO/H2
98+% Removal
Sulfur
Sulfur Recovery
Claus/Scot
PRE-COMBUSTION
Treatment of Pollutants
•High pressure
•Low Volume
•Concentrated stream (easier to treat)
Steam Turbine
Electricity
Air
HRSG
Combustion Turbine
Electricity
Compressed Air to ASU

GASIFICATION – Wide Range of Fuels and Products



•Source: "Shell Coal Gasification in North America", by Milton Hernandez, Shell U.S. Gas & Power, presented at GTC, Oct. 2, 2006

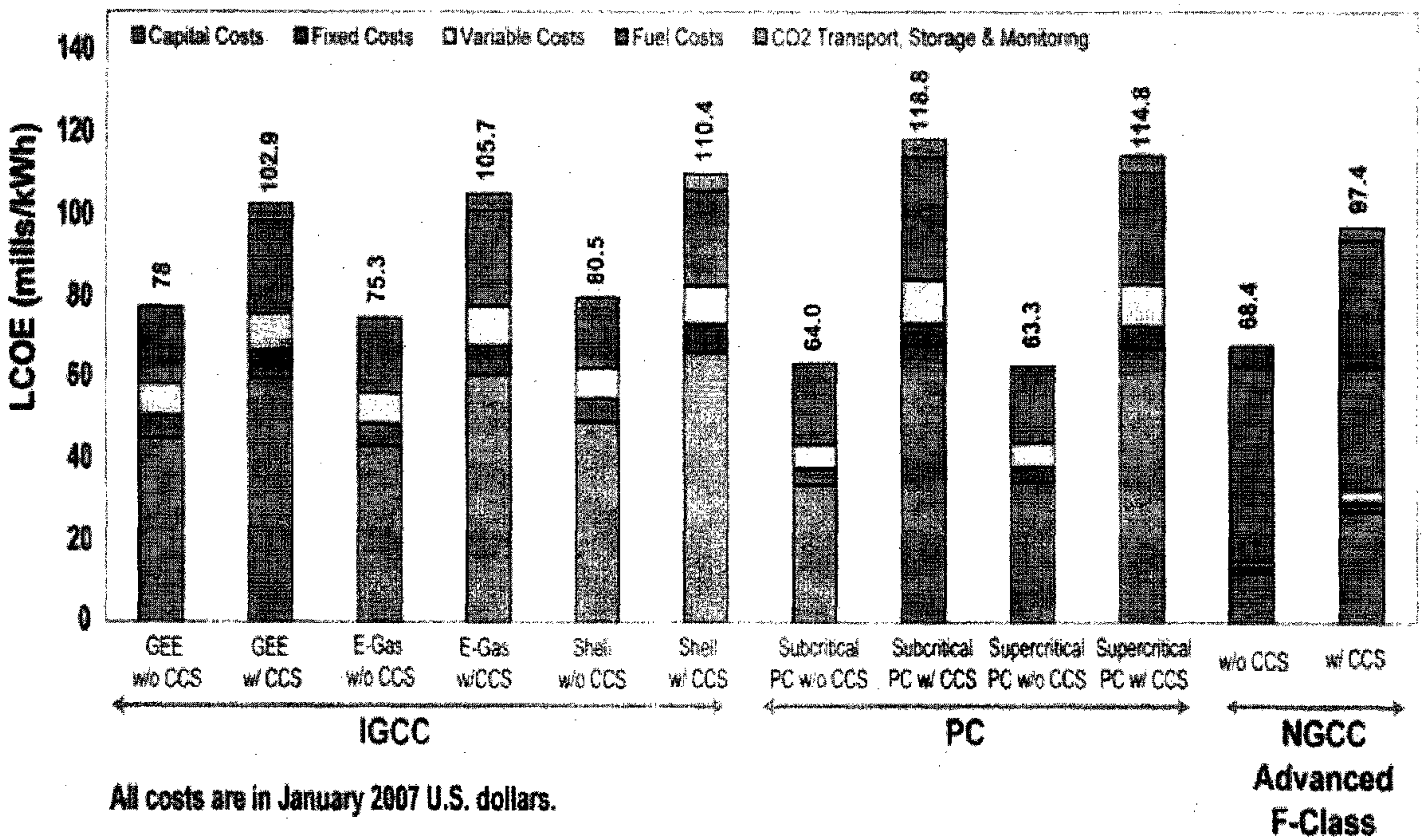
Table 3.7 Relative Cost of Electricity from PC and IGCC Units, without and with CO_2 Capture*

	MIT	GTC	AEP	GE
PC no-capture, reference	1.0	1.0	1.0	1.0
IGCC no-capture	1.05	1.11	1.08	1.06
IGCC capture	1.35	1.39	1.52	1.33
PC capture	1.60	1.69	1.84	1.58

**Included are: the MIT Coal Study results (MIT), the Gasification Technology Council (GTC) [56], General Electric (GE) [57], and American Electric Power (AEP) [58].*

Source: "The Future of Coal" by the Massachusetts Institute of Technology (MIT), April 2007, page 36.

Figure 7. Levelized Cost-of-Electricity



Source: "Fossil Energy Power Plant Desk Reference", DOE/NETL-2007/1282, May 2007, Overview-6, Figure 7.

Table III-2, Example Calculation of True Economic Impact of IGCC and SCPC[46]

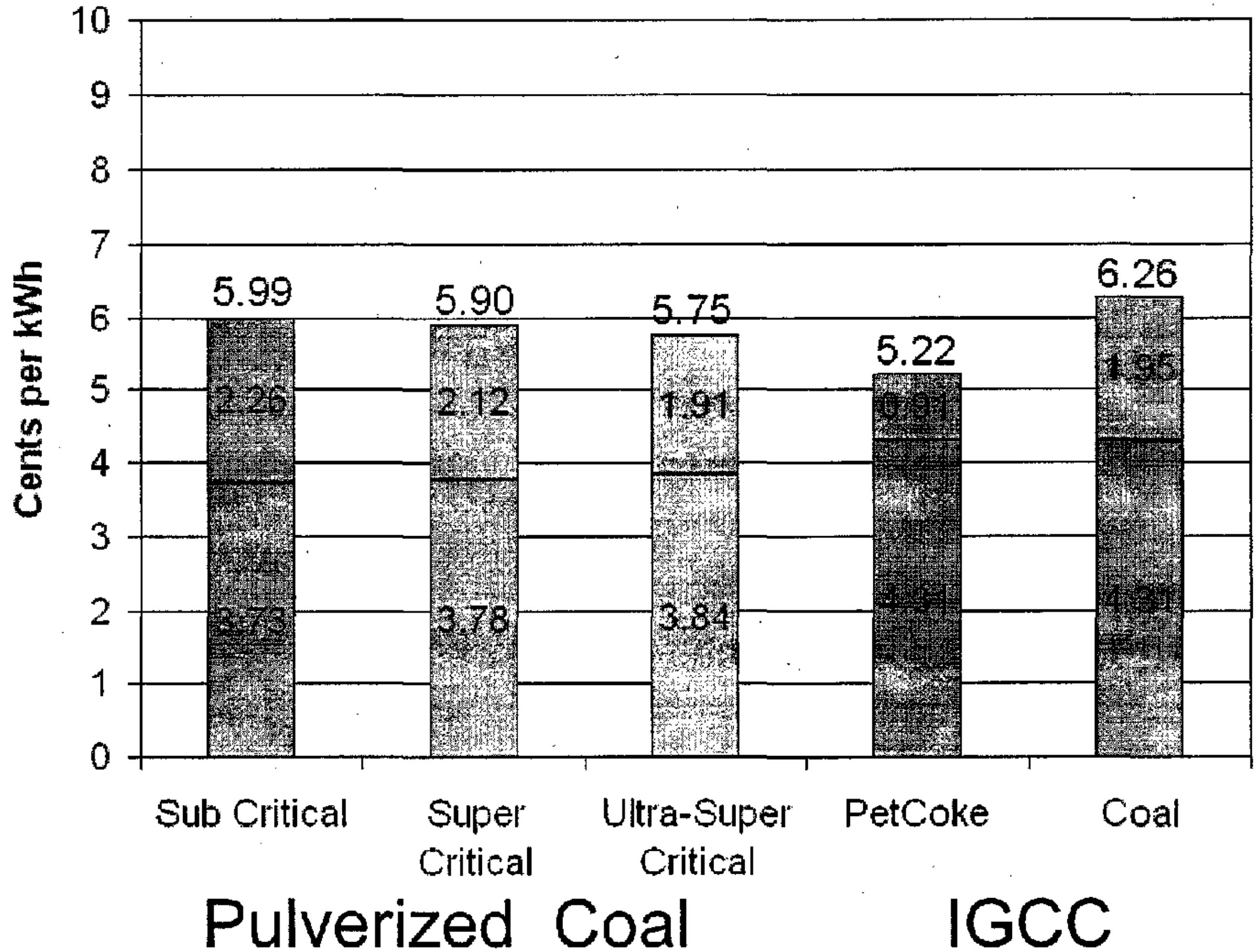
Facility Parameter	**IGCC**	**SCPC**
Output, Gross, MW	575.00	541.00
Output, Net, MW	500.00	500.00
Cost of Electricity Generation, \$/MWh, net	**68.20**	**58.94**
PM (Filterable), lb/MWh (gross)	0.052	0.100
SO2, lb/MWh (gross)	0.089	0.541
NOx, lb/MWh (gross)	0.375	0.494
PM Damages at \$17.00/kg, \$/MWh (gross)	1.95	3.75
SO2 Damages at \$10.44/kg, \$/MWh (gross)	2.05	12.45
NOx Damages at \$16.00/kg, \$/MWh (gross)	13.23	17.43
Total of Above Damages, \$/MWh (net)	**19.81**	**36.39**
Total Costs, \$/MWh, net	**88.01**	**95.33**

[46] All values based on EPA Footprints Report estimates for sub-bituminous coal units. 85% capacity factor, 17.5% capital recovery factor, and \$1.80/MMBtu delivered coal price assumed for both technologies. Emissions rates and costs for IGCC do not include SCR.

Median costs used for environmental and health damages as provided from published studies – see "World Energy Assessment", by United Nations Development Programme, 2000, Table 8.1

Source: Clean Air Task Force (CATF) comments dated September 28, 2007 to the Michigan Department of Environmental Quality on their July 26, 2007 Fact Sheet: Environmental Permitting of Coal-Fired Power Plants in Michigan

Cost of Electricity Comparison Chart for Florida



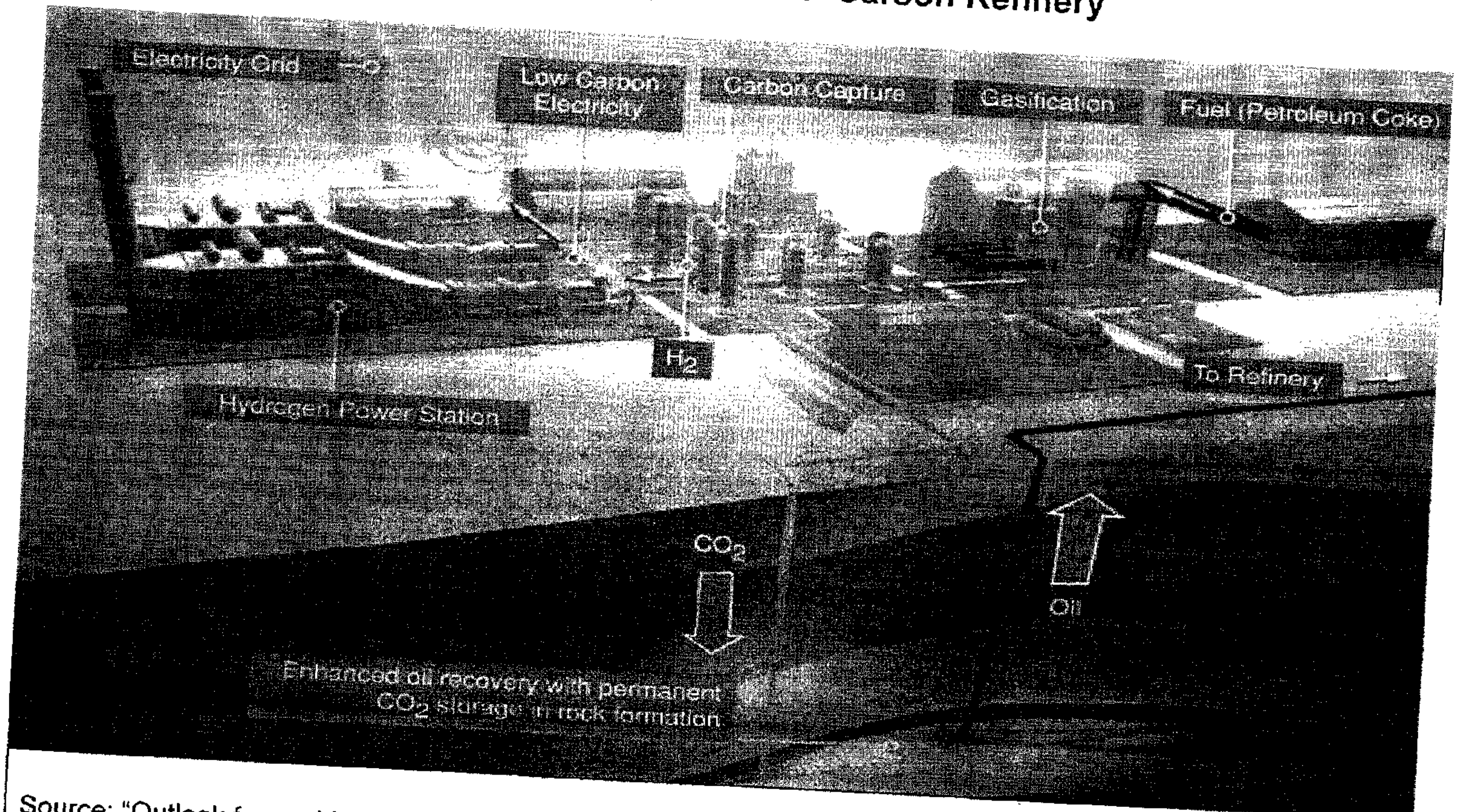
Fuel Costs
Non-Fuel Costs

Coal Cost	$2.38/MMBtu
PetCoke Cost	$1.11/MMBtu

PC capacity factor	85%
IGCC capacity factor	80%

rcfurman2@aol.com

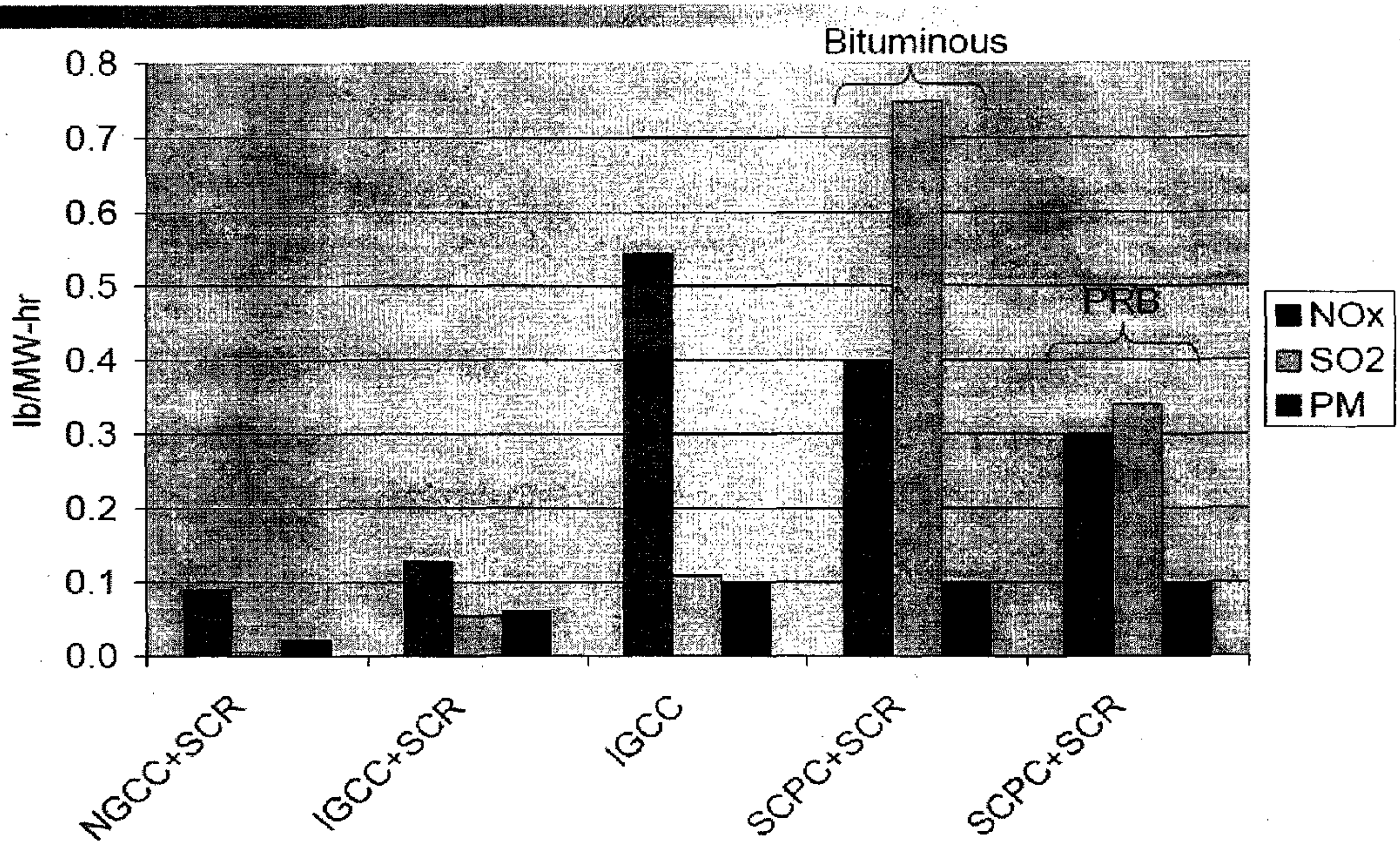
Proposed 500 MW IGCC Plant Using Petcoke with CO2 Capture and Enhanced Oil Recovery at the BP Carson Refinery



Source: "Outlook for coal-based IGCC power generation", Gas Turbine World, January – February 2007, p. 25.

Emissions Comparison – State-of-the-Art Coal Combustion, IGCC, and NGCC

Values represent technology capability, not permit levels



Source: "Gasification 101", by Jeffrey Phillips, Electric Power Research Institute (EPRI), presented at Gasification Technologies Workshop in Bismarck, ND June 28-29, 2006, page 27.

IGCC and Pulverized Coal (PC) Air Emissions Comparisons

	Bituminous Coal			
Parameter	IGCC Slurry Feed Gasifier	Sub-critical PC	Super-critical PC	Ultra Super-critical PC
NO_x (as NO_2)[1] (lb/MMBtu)	0.043	0.056	0.056	0.055
SO_2 [2] (lb/MMBtu)	0.038	0.080	0.080	0.079
PM [3] (lb/MMBtu)	0.006	0.011	0.011	0.011
Mercury [4] (lb/yr)	24.1	29.3	27.4	24.5

Source: Environmental Footprints and Costs of Coal-Based Integrated Combine Cycle and Pulverized Coal Technologies, U.S. Environmental Protection Agency, EPA-430/R-06/006, July 2006

Note: Lb/MMBtu and lb/yr values calculated from EPA's lb/MWH and heat rate data.

1 The NO_X emission comparisons are based on emission levels expressed in ppmvd at 15% oxygen for IGCC and lb/MMBtu for PC.

2 SO_2 removal efficiency basis is 98% for PC. Removal efficiency basis for IGCC is 99%.

3 Particulate removal is 99.9% or greater for the IGCC, 99.8% for bituminous coal and 99.7% for sub-bituminous.

4 Mercury emission rates are based on the premise that mercury-specific controls are installed and operate at 90% efficiency.

Source: Testimony of Paul Carpinone, Tampa Electric Company, to Florida Public Service Commission, July 20, 2007, p 14, for Tampa Electric's Petition to Determine Need for Polk Power Plant Unit 6.

SUMMARY OF RECENT IGCC PERMITS AND PROPOSED PERMIT LEVELS

	Approved Permit						Application Filed, Draft Permit Not Issued Yet					
Pollutant	Global Energy Lima, Oh, 58 MW	Kentucky Pioneer Energy, KY	Wisconsin Electric Elm R 600 MW	ERORA Cash Creek KY, 630 MW	Southern Illinois Clean Energy Complex, IL, 64 MW & 110 MMSC methane	ERORA, Taylorville, IL MW	Nueces, TX 600 MW	Energy Northwest WA, 600 MW	AEP, OH, 629 MW	AEP, WV, 629 MW	Mesaba One (606 MW), Mesaba Two (606), MN, Total 1,2 MW	Duke, Edwardsport, IN, 630 MW
	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)
SO2	0.021	0.032 -3 hr ave	0.03 -24 hr ave	0.0117 -3 hr ave	0.033 -30 day ave	0.0117 -3 hr ave	0.01	0.016 -3 hr ave	0.017	0.017	0.02	Repower, n from BACT
NOx	0.097	0.0735 -3 hr ave	0.07 (15 ppmdv) -30 day ave	0.0246-24 hr ave	0.059 -30 day ave	0.0246 -24 hr ave	0.01	0.012 -3 hr ave	0.057	0.057	0.05	Repower, n from BACT
Mercury			.56 x 10-6	.197 x10-6 (1)	.547 X10-6	.19 x 10-6 (1)	1.825 x10-6	1.1 x10-5			90% removal, .026 tons Phase I and II total	.008 tons/y
PM	0.01	.0.011	0.011 (backhalf)				0.015	0.001			0.00	18.1 lbs/hr
PM10			0.011 (backhalf)	0.0063 -3 hr ave (filterable)	0.00924 (filterable)	0.0063 -3 hr ave (filterable)	0.014		.006 (filterable)	.006 (filterable)		
VOC	0.0082	0.0044	0.0017 -24 hr ave (LAER) (3)	0.006 -24 hr ave	0.0029	0.006 -24 hr ave	0.004	0.003	0.001	0.001	0.0032	1.4 ppmvw
Sulfuric Acid Mist			0.0005 -3 hr ave	0.0026 -3 hr ave	0.0042 -30 day ave	0.0026 -3hr ave	0.0001		98 tons/yr	98 tons/yr		
Fluorides (2)												
CO	0.137	0.032 -3 hr ave	.030 -24 hr ave	0.036 -24 hr ave	0.04 -30 day ave	0.036 -24 hr ave	0.04	0.036	0.031	0.031	0.034	15 ppmvd
Lead			0.0000257									
Sulfur Control Techn	MDEA	MDEA	MDEA	Selexol	MDEA	Selexol	Selexol	Selexol	Selexol	Selexol	MDEA	Selexol
Nox Control Technol	Diluent injection	Diluent injection	Diluent injection	Diluent/SCR	Diluent injection	Diluent/SCR	Diluent/SCR	Diluent/SCR	Diluent injection	Diluent injection	Diluent injectio	Diluent/SCR

(1) Application estimates this emission limit but does not proposed an emission limit
(2) No limit established. Fluorides from IGCC plants are below PSD significance
(3) Polk IGCC also has this emission rate effective July 2003 as set by BACT.

Source: Declaration of John Thompson, Director of the Clean Air Transition Project for the Clean Air Task Force, submitted to EPA for the Desert Rock air permit, dated November 10, 2006, page 13.

EMISSIONS FROM AMPS – OHIO PLANT VERSUS RECENT IGCC PERMIT APPLICATIONS

	AMPGS	IGCC			
	Proposed Emission Rates	Sulfur control using MDEA	Sulfur control using Selexol	Nitrogen control using diluent injection	Nitrogen control using both diluent injection and SCR
	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)
SO2	0.15	0.025 - 0.033 (17% - 22%)	0.0117 - 0.019 (8% - 13%)		
NOx	0.07			0.057 - 0.07 (81% - 100%)	0.012 - 0.025 (17% - 36%)
PM	0.015	0.001 – 0.0063 (7% - 42%)			
CO	0.154	0.03 - 0.04 (19% - 26%)			
Hg	0.0000019	0.00000019 - 0.00000056 (10% - 29%)			

Source: IGCC Data from Declaration of John Thompson, Director of the Clean Air Transition Project for the Clean Air Task Force, submitted to EPA for the Desert Rock air permit, dated November 10, 2006, page 15.

Total Tons per Year of Pollutants from AMPS-Ohio and IGCC Plant of Same Size (960 MW)

Emissions	AMPS–Ohio PC[1]	Taylorville-IGCC [2]	IGCC vs PC % of EMISSIONS
NO_X	3,194	1,128	35 %
SO_2	6,820	654	10 %
Particulate	1,182	636	54 %
Mercury	0.086	0.057 (0.008)	66 % (10%)
H_2SO_4	343	115	34 %
CO	7,009	1,566	22 %
VOC	167	50	30 %

1 "STAFF DETERMINATION FOR THE APPLICATION TO CONSTRUCT UNDER THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS FOR AMERICAN MUNICIPAL POWER GENERATING STATION LETART FALLS, OHIO", PTI NUMBER 06-08138, August 9, 2007, by Ohio Environmental Protection Agency, Table 1.

2 "Construction Permit - Prevention of Significant Deterioration Approval for Taylorville IGCC Plant", June 5, 2007, issued to Christian County Generation, Appendix Table III, page 1-4 and page 3.

RCFurman 10/2/07

Proposed Permit Emission Rates for PC Plants

Emissions	AMPS- Ohio[1]	FPL – Glades[2]	Taylor Energy Center[3]
NOx lb/MMBtu	**0.07**	**0.05**	**0.05**
SO_2 lb/MMBtu	**0.15**	**0.04**	**0.04**
Particulate lb/MMBtu	**0.015**	**0.013**	**0.013**
Mercury lb/TBtu	**1.9**	**1.2**	**0.9**

1 "STAFF DETERMINATION FOR THE APPLICATION TO CONSTRUCT UNDER THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS FOR AMERICAN MUNICIPAL POWER GENERATING STATION LETART FALLS, OHIO", PTI NUMBER 06-08138, August 9, 2007, by Ohio Environmental Protection Agency.

2 "Air Permit Application and Prevention of Significant Deterioration Analysis for FPL Glades Power Park Glades County, Florida", prepared for Florida Power & Light Company, by Golder Associates Inc., December 2006.

3 "Air Construction/ Prevention of Significant Deterioration Permit Application for Taylor Energy Center", Prepared for JEA, Reedy Creek, City of Tallahassee and FMPA, prepared by Environmental Consulting & Technology Inc. and Sargent & Lundy, May 2007.

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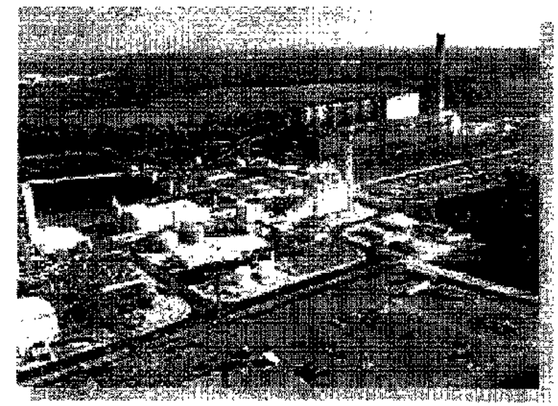
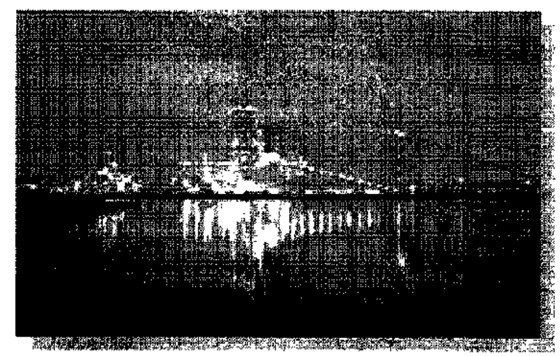
IGCC Technology in Early Commercialization

U.S. Coal-Fueled Plants

- **Wabash River**
  - 1996 Powerplant of the Year Award*
  - Achieved 77% availability **
- **Tampa Electric**
  - 1997 Powerplant of the Year Award*
  - First dispatch power generator
  - Achieved 90% availability **





Nation's first commercial-scale IGCC plants, each achieving
≥ 97% sulfur removal
≥ 90% NO_x reduction

NETL

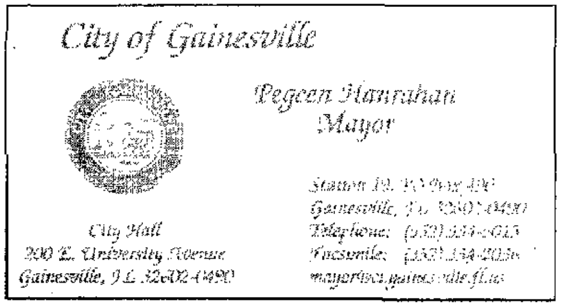
*Power Magazine

** Gasification Power Block

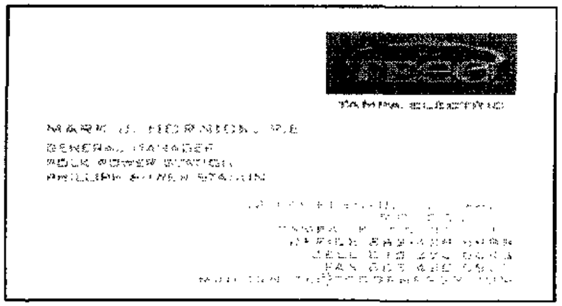
Source: Department of Energy/NETL Presentation, <u>Overview of Coal Gasification Technologies,</u> by Gary Stiegel, presented at NSTAR Meeting, Pittsburgh, PA, Oct. 27,2006.

References to Contact

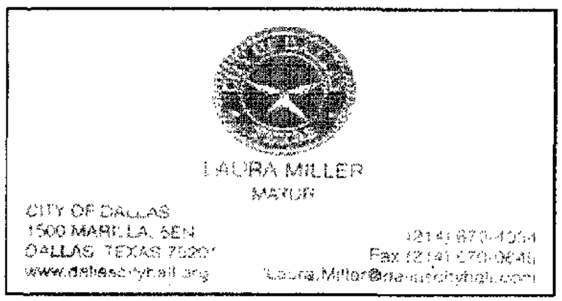
Pulverized Coal vs. IGCC Plants



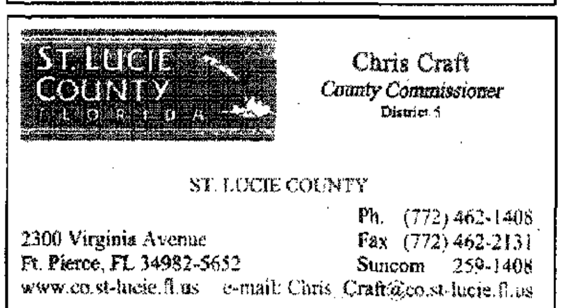
City of Gainesville hired ICF Consultants directly. ICF evaluation selected IGCC as best choice. Gainesville issued RFI for partners in IGCC plant.



Tampa Electric has operated an IGCC plant for over 10 years. Tampa Electric has announced an additional 630MW IGCC plant to be operating in 2013. The plant manager can answer any questions. Tours of the plant are available.



The Mayor of Dallas has toured the Tampa Electric IGCC plant and is knowledgeable about power plants and pollution control equipment. She has formed a coalition of 22 mayors in Texas to encourage the use of IGCC plants.



The St. Lucie County Commission voted 6 to 0 against a 1700MW PC plant proposed by FPL. Commissioner Chris Craft traveled to the Taylor County Commission hearing to advise them on St. Lucie's experience.

"It is difficult to get a man to understand something when his salary depends upon his not understanding it."

- Upton Sinclair

World Gasification Survey: Summary Operating Plant Statistics 2004

117 Operating Plants

385 Gasifiers

Capacity~**45,000** MWth

Feeds

Coal **49%**, Pet. Resid. **36%**

Products

Chemicals **37%**, F-T **36%**, Power **19%**

Growth Forecast **5% annual**

Gasification Technologies Council

Commercially Operating IGCC Projects Worldwide. Table lists 14 commercially operating IGCC plants worldwide (including one now undergoing commissioning) that provide close to 3900 MW of generating capacity. Plants use a variety of feedstock coals, petroleum coke and other refinery residues. Nuon Buggenum plant recently introduced biomass to supplment its coal feedstock. The syngas-modified V94 gas turbines are Siemens designs built by Ansaldo. The Frame machines are GE designs.

Project	Startup	Rating	Feed	Product	Gasifer	Gas Turbine
Nuon (Demkolec), Buggenum, The Netherlands	1994	250 MW	coal/biomass	power	Shell	V94.2
Wabash (Global/Cinergy), Indiana USA	1995	260 MW	coal/coke	repowering	Conoco Phillips	1xFr 7FA
Tampa Electric, Polk County, Florida USA	1996	250 MW	coal/coke	power	GE/Texaco	1xFr 7FA
Frontier Oil, El Dorado, Kansas USA	1996	45 MW	coke	power/steam	GE/Texaco	1xFr 6B
SUV, Czech Republic	1996	350 MW	coal/coke	power/steam	Lurgi	2xFr 9E
Schwarze Pumpe, Germany	1996	40 MW	lignite/waste	power/methanol	Future Energy	1xFr 6B
Shell Refinery, Pernis, The Netherlands	1997	120 MW	visbreaker/tar	power/steam/H2	**Shell**	2xFr 6B
Elcogas S.A., Puertollano, Spain	1998	300 MW	coal/coke	power	Prenflo	1x V94.3
ISAB Energy, ERG/Mission, Italy	2000	520 MW	asphalt	hydrogen/power	GE/Texaco	2x V94.2K
Sarlux, Saras/Enron, Sardinia, Italy	2001	545 MW	visbreaker/tar	power/steam/H2	GE/Texaco	3x Fr 9E
Exxon Chemical, Singapore	2001	160 MW	ethylene tar	power/steam	GE/Texaco	2xFr 6FA
Api Energia, Falconara, Italy	2002	280 MW	visbreaker/tar	power	GE/Texaco	1xKA 13E2
Valero (Premcor), Delaware City USA	2003	160 MW	coke	repowering	Alstom GE/Texaco	2xFr 6FA
Nippon Refining (NPRC), Negishi, Japan	2003	342 MW	asphalt	power	GE/Texaco Mitsubishi	1x701F
Eni Sannazzaro, AGIP Petrolia, Italy	2006	250 MW	oil residues	power/steam/H2	Shell	V94.2K
Total generating capacity		**3872 MW**				

Source: Luke O'Keefe, Burns & Roe

Proposed IGCC and Gasification Plants North America (GTW January 2007)

This is a working reference of proposed projects in North America, compiled from a variety of sources. Five projects highlighted in yellow were awarded substantial EPAct 2005 tax incentives in December 2006.

Project/Feed	Nominal Net Output	Gasifier	Gas Turbine	Engineer	Year	Comments
Agrium, Kenai, Alaska sub-bituminous	200 MW poly*	GE Energy	GE Frame		2011	*ammonia/urea
Alma, Michigan coal	MW + poly*		N/A			*plus methanol
American Electric Power, Ohio coal	630 MW	GE Energy	2 x Fr 7FB	Bechtel	2010	
American Electric Power, West Virginia coal	630 MW	GE Energy	2 x Fr 7FB	Bechtel	2010	
Baard Energy/Rentech, Ashtabula, Ohio Illinois coal	100 MW poly*	Shell	1 x Fr 6FB			*35,000 bpd
Basin Electric, South Dakota PRB coal		GE Energy	GE Frame			
BP Edison Refinery, Carson, California pet coke	390 MW poly*	GE Energy	1 x Fr 7FB			*plus hydrogen
Citgo, Lake Charles, Louisiana pet coke	MW + poly*		N/A			*plus hydrogen
Clean Coal Power, Vandalia, Illinois coal	MW + polygen*		N/A			*100,000 bpd naptha
CoP Refineries, Various Sites pet coke	hydrogen*	CoP E-Gas	N/A			*hydrogen/steam
DKRW, Medicine Bow, Wyoming So Wyom coal	140 MW poly*	GE/Rentech	N/A			*11,000 bpd dist/naptha
Duke/Cinergy, Edwardsport, Indiana coal	630 MW	GE Energy	2 x Fr 7FB			
Energy Northwest, Port Kalama, Washington coal/pet coke	600 MW		N/A		2011	
Erora/Tenaska, Taylorville, Illinois Illinois coal	630 MW poly*	GE Energy	2 x Fr 7FB	Burns	2010	*synthetic natural gas
Erora/Tenaska, Cash Creek, Kentucky (GE Energy Financial taking 20% equity position) Ky # 9 coal	630 MW poly*	GE Energy	2 x Fr 7FB		2010	*substitute natural gas
Excelsior Energy, Holman, Minnesota (Phase 1) PRB/pet coke	606 MW *	CoP E-Gas	2 x S5000F	Fluor	2011	*450 MW power purchase agreement pending
Excelsior Energy, Holman, Minnesota (Phase 2) PRB/pet coke	606 MW	CoP E-Gas	2 x S5000F	Fluor	2012	
FutureGen Alliance, Site TBD (DOE to pay two-thirds for zero emissions demo plant) bitum/sub-bitum	275 MW poly*		N/A		2012	*plus hydrogen
GRE, North Dakota lignite	10,000 bpd*	Shell/ Siemens	N/A			*Fischer Tropsch liquids

Hunton Energy, Fort Bend County, Texas (Phase 1)						
petcoke	600 MW*	GE or CoP	N/A		2012	*with CO_2 capture and sequestration
Hunton Energy, Fort Bend County, Texas (Phase 2)						
pet coke	600 MW*	GE or CoP	N/A		2013	*with CO_2 capture and sequetsration
Indiana Gasification, Indiana (Pub Service, Vectren, Citizen's Gas to take output)						
high-sulfur coal	syngas*	GE Energy	N/A		2011	*100 MM scfd
Mississippi Power, Kemper County, Mississippi						
lignite	700 MW	Kellog Brn Root		N/A		
Mosaic/US Syngas, St. James Parish, Louisiana						
pet coke	hydrogen+poly*	GE Energy	N/A	Japan		*1.33 MM tpy ammonia 230 MM scfd syn nat gas
Mountain Energy, Idaho						
coal	hydrogen		N/A			
North West Upgrading, Edmonton, Canada						
oilsands	hydrogen, syngas*		Lurgi MPG	N/A	2010	*120 MM scfd 50,000 bpd capacity
NRG Energy, Huntley, New York						
coal	630 MW	Shell	N/A		2012	brownfield coal station
NRG Energy, Indian River, Delaware						
coal	630 MW	Shell	N/A		2011	brownfield coal station
NRG Energy, Montville, Connecticut						
coal	630 MW	Shell	N/A			existing NG comb cycle
OPTI/Nexen, Fort McMurray, Canada						
oilsands	MW + poly*	Shell	N/A		2008	*hydrogen and syngas 58.500 bpd capacity
PacifiCorp, Utah (Hunter)						
coal	250-600 MW		N/A		2014	
PacificCorp, Wyoming (Jim Bridger)						
sub-bituminous	250-600 MW		N/A		2014	
PacificCorp/MEHC, Wyoming (M&M Ranch)						
lignite	250-600 MW		N/A		2014	
Peabody, New Mexico						
coal	polygen*		N/A			*synthetic natural ga and coal to liquids
Peabody/Rentech, Midwest						
coal	polygen*		N/A			*10,000 scfd syn nat gas and 30,000 bpd
Peabody/Rentech, Montana						
coal	polygen*		N/A			*10,000 scfd syn nat gas and 30,000 bpd
Peace River Oil, Red Deer, Canada						
oilsands	MW + poly*				2010	*plus hydrogen andsyngas
Power Holdings, Jefferson Co, Illinois						
Illinois coal	syn nat gas*	GE/Bechtel	N/A		2009	*140 MM scfd SNG

Rentech, Natches, Michigan						
coal	F-T diesel*		N/A			Fischer-Tropsch
Rentech Energy Solutions, Mingo Co, West Virginia						
coal	F-T diesel*		N/A			*20,000 bpd F-T liquids
Rentech/Royster, East Dubuque, Illinois						
coal	75 MW poly*	CoP E-Gas	N/A	Kiewit		*930 tpd ammonia and 1800 bpd fuel
Sask Power, Canada						
pet coke	300 MW poly*		N/A	Jacobs		*plus hydrogen and syngas
Sherritt international, Dodds-Roundhill, Canada						
oilsands	polygen*					*hydrogen and syngas CO_2 capture for EOR
Southern Company, Orlando, Florida						
PRB coal	285 MW	KBR Transport	1 x Fr 7FB	KBR		
Southwestern Power, Bowie Station, Arizona						
coal			N/A			
Steelhead, Southern Illinois						
Illinois coal	630 MW poly*	CoP E-Gas	2 x S5000F	Fluor		*100 MM scfd syn nat gas
Summit Power, Washington						
coal	365 MW poly*		1 x S5000F			*plus syn natural gas
Suncor Energy, Voyager II, Fort McMurray, Canada						
pet coke	polygen*		N/A		2012	*hydrogen and SNG
Synenco/Sinopac, Northern Lights Upgrader, Edmonton, Canada						
oilsands	poygen*	GE license	N/A			*hydrogen and syngas 100,000 bpd capacity
Synfuel, Ascension, Louisiana						
lignite	MW + poly*	GE Energy	GE Frame			*chemicals, SNG,acid
Synfuel, Oklahoma						
coal	polygen*	Siemens	N/A			*Fischer -Tropsch liquids
Tampa Electric Unit-2, Polk County, Florida						
bituminous	630 MW	GE Enery	2 x Fr 7FB		2013	
Texas Energy/Eastman, Longview, Texas						
pet coke	polygen*	GE Energy	N/A			*syngas, methanol
Tondu-Nueces, Corpus Christi, Texas						
coal/pet coke	630 MW	Shell	2 x S5000F			
West Hawk Development, Northwest Canada						
coal	syn nat gas*		N/A			*550 MM scfd
WMPI, Gilberton, Pennsylvania						
anthracite waste	133 MW poly*	Shell	N/A			*5,000 bpd FT diesel and 4,000 tpy sulfur
Xcel, Colorado						
coal	300-350 MW*				2013	*with CO_2 capture and sequestration

Source: EPRI data, news releases, websites, permit applications, presentations, GTW industry contacts

Proposed IGCC and Gasification Plants Ex-North America (GTW January 2007)

This is a working reference of proposed projects being developed around the world. Many of them are being built for polygeneration of electric power and chemical products from low grade feedstock and waste. Several will operate to capture and store carbon dioxide.

Project/Feed	Output	Gasifier	GT Model	Engr	Year	Products
Bharat Heavy Electricals, Auralya, India coal	125 MW*	BHEL Fluid Bed		BHEL	2009	*demo plant
BP/CoP/Shell, Peterhead, United Kingdom natural gas	475 MW poly*	Thermal Reformer			2010	*hydrogen fuel and CO2 capture for EOR injection
Centrica/Progressive Energy, Teeside 1, United Kingdom coal/pet coke	800 MW poly*				2012	*hydrogen fuel and CO2 capture for EOR injection
Centrica/Progressive Energy, Teeside 2, United Kingdom coal/pet coke	800 MW poly*				2013	*hydrogen fuel and CO2 capture for EOR injection
China Fertilizer BGL Demo Plant, China lignite		BGL				
Clean Coal Power Demo Plant, Iwaki City, Japan bituminous	250 MW	MHI air-blown	1 x M701DA	MHI	2007	42% net plant efficiency LHV
E.On/PowerGen, Killingholm, Germany coal						
Fujian Refinery, China asphalt	450 MW poly*	Shell	2 x Fr 9E	FW		*3 x 1200 tpd hydrogen
Hatfield/KRU Russia, Hatfield, United Kingdom coal	430 MW*					*CO2 capture for enhanced oil recovery injection
HRL/Harbin Power, Victoria, Australia brown coal		HRL Fluid Bed			2010	
Indian Oil Refinery, Madras, India residue	MW + poly*					*hydrogen, also steam
Jindal Steel, Orissa States, India high ash coal	syngas fuel*	Lurgi Mark IV				*320,000 Nm3/hr
Lotos Group, Gdansk, Poland asphalt	MW + poly*	Shell				*1600 tpd feed, hydrogen
Nuon, Eemshaven, Netherlands coal/biomass	1200 MW	Shell license		Lummus	2011	
Progressive Energy, South Wales, United Kingdom (multiple sites) coal/pet coke	460 MW*					* CO2 capture for enhanced oil recovery injection
RWE, Germany lignite	450 MW*				2014	*360 MW net and 300 tph carbon dioxide capture
Schwarze Pumpe, Spreetal, Germany lignite	300 MW poly*	Siemens	1 x S3000E		2009	*plus methanol
Schwarze Pumpe, Spreetal, Germany lignite	polygen*	Siemens			2009	*3000 bpd F-T liquids

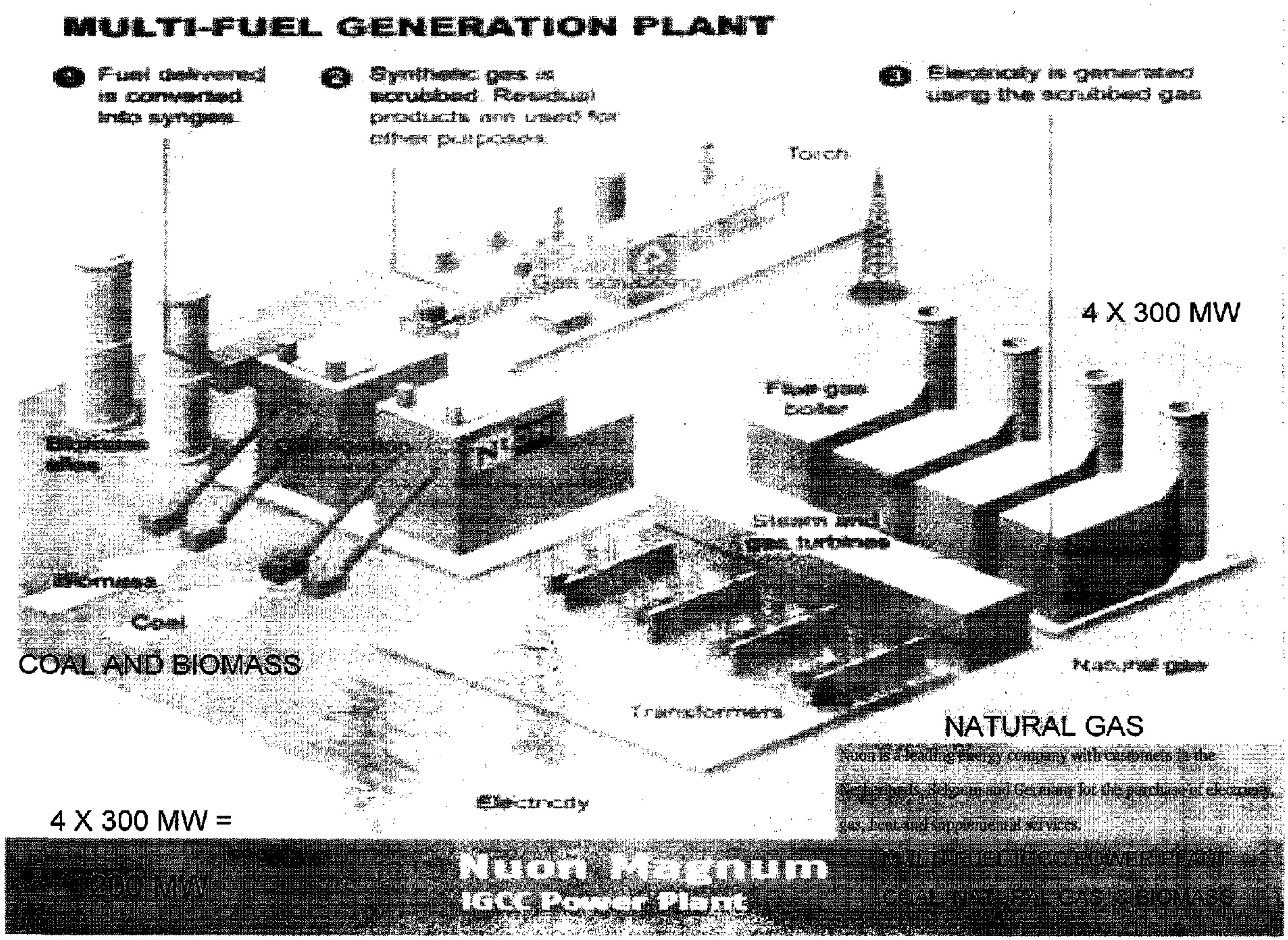
SES/Hai Hua, Zaozhuang, Shandong, China				
waste coal	MW + poly*	U-Gas		*25 MM scfd syn nat gas
Sines Refinery, Sines, Portugal				
heavy oil	500 MW poly*		2013	*plus methanol
Shell/Anglo American, Latrobe, Victoria, Australia				
coal	MW + poly*	Shell		*coal-to-liquids, CO2 capture
Shenhua/Shell, Inner Mongolia, China				
coal	polygen*	Shell (2)	2007	*hydrogen and 1 MM tpy liquids
Shenhua/Shell, Ningxia, China			AMEC	
coal	polygen*	Shell		*3 MM tpy F-T liquids
Shenhua/Sasol, Multiple sites, China				
coal	polygen*	Sasol		3 x 3 M tpy F-T liquids
Stanwell ZeroGen, Queensland, Australia				
sub-bitum	100-300 MW*	Shell	2010	*CO2 capture for enhanced oil recovery injection
Statoil, Halten, Norway				
natural gas	polygen*	Shell		*CO2 capture for enhanced oil recovery injection

Source: EPRI data, news releases, websites, permit applications, presentations, GTW industry contacts

Proposed "carbon capture and storage" power plant projects (275 MW and above).
Europe, particularly the UK, taking lead in number of proposed power projects featuring CO_2 capture and storage. Recent reopening of Hatfield Colliery, with support of Russion energy interests, may be forerunner to first plant to enter operation. According to list, a number of large commercial plants could be running before US FutureGen demo plant scheduled for 2012 startup.

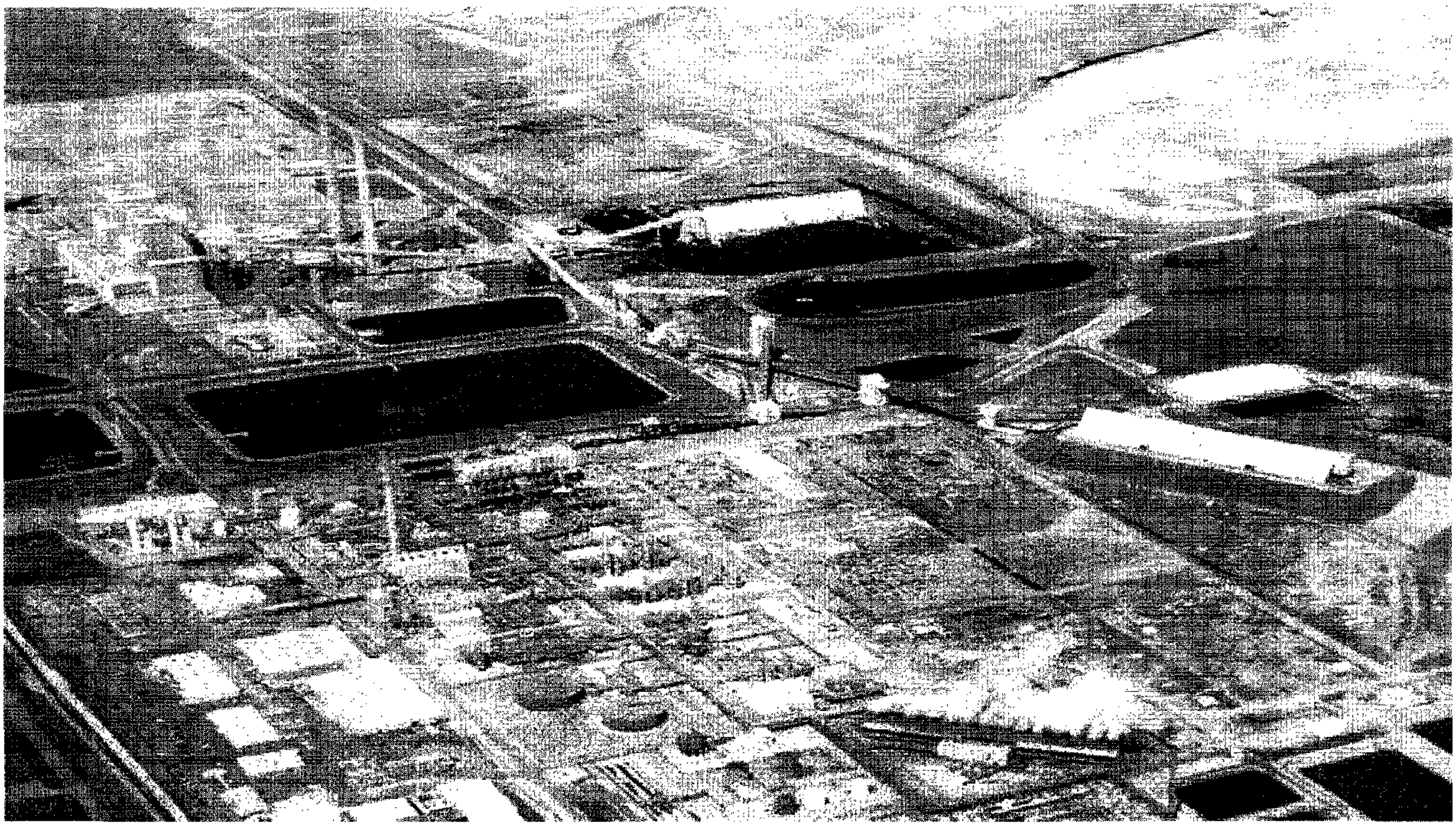
Company and project	Plant output	Capture technology	Start
Progressive Energy, Teeside, UK petcoke	800 MW +H2	IGCC + shift + precombustion	2009
BP Peterhead/Miller, Scotland natural gas	475 MW	Auto reformer + precombustion	2010
Powerfuel, Hatfield Colliery, UK coal	900 MW	IGCC + shift + precombustion	2010
BP Carson, USA petcoke	500 MW	IGCC + shift + precombustion	2011
E.On, Killingholme, UK coal	450 MW	IGCC + shift + precombustion	2011
SaskPower, Saskatchewan, Canada lignite	300 MW	PC + post-combustion or oxyfuel	2011
Siemens/Spreetal, Germany coal	1000 MW	IGCC + shift + precombustion	2011
Statoil/Shell, Draugen, Norway natural gas	860 MW	NGCC + post-combustion amine	2011
FutureGen, USA coal	275 MW	IGCC + shift + precombustion	2012
Stanwell, Queensland, Australia coal	275 MW	IGCC + shift + precombustion	2012
Vattenfall/Schwarze Pumpe, Germany lignite	300 MW	Oxyfuel + post-combustion	2012
RWE, Germany coal	450 MW	IGCC + shift + precombustion	2014
RWE, Tilbury, UK coal	500 MW	SCPC + post-combustion	2016

Source: Based on 2006 report by Gibbins and Chalmers, "Carbon Capture and Storage", Mech Engr Dept., Imperial College London, plus company websites, press releases, industry communications.

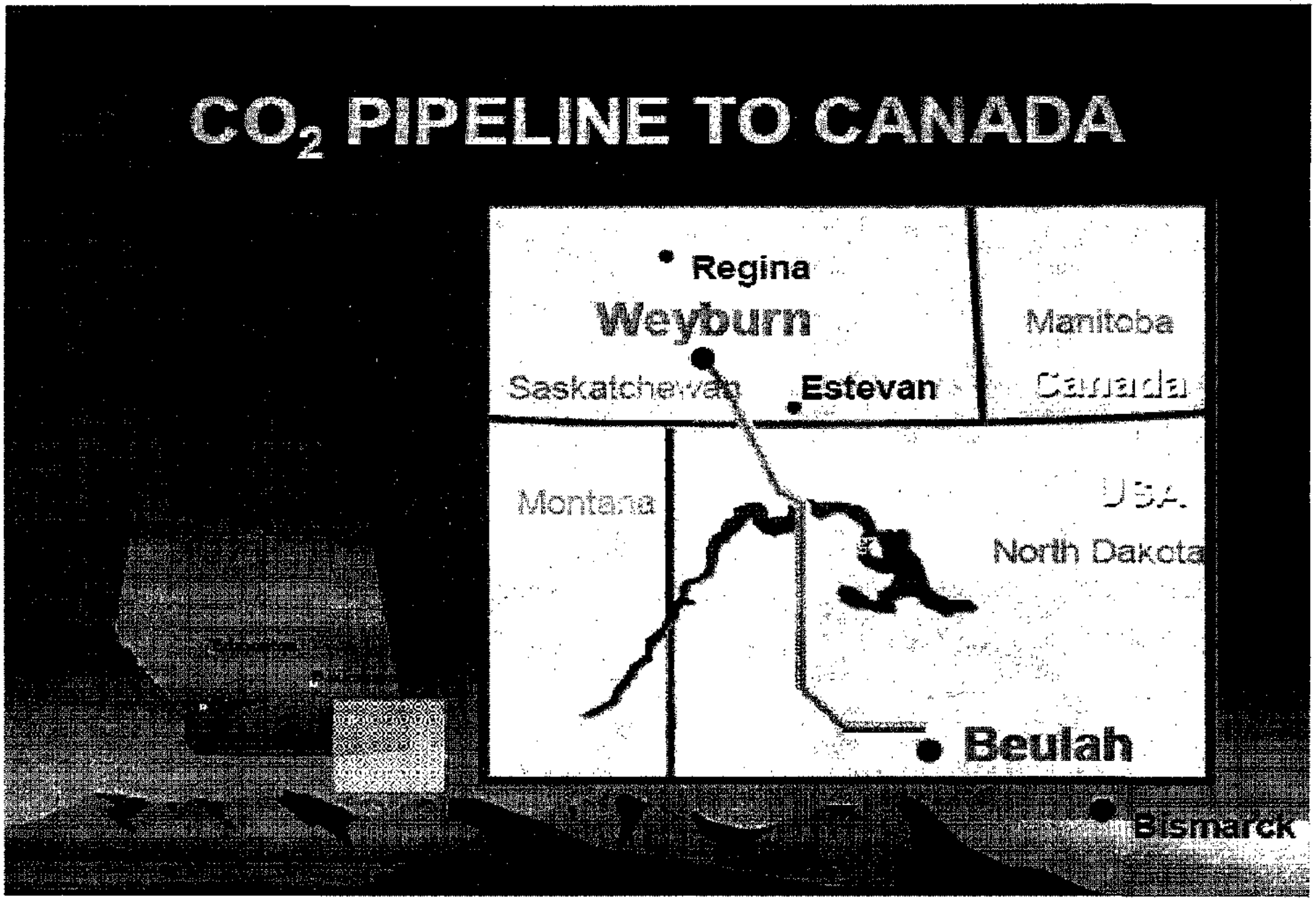

MULTI-FUEL GENERATION PLANT
1 Fuel delivered is converted into syngas.
2 Synthetic gas is scrubbed. Residual products are used for other purposes.
3 Electricity is generated using the scrubbed gas
Torch
Flue gas boiler
Steam and gas turbines
Transformers
Biomass
Coal
Natural gas
Electricity
COAL AND BIOMASS
NATURAL GAS
4 X 300 MW
4 X 300 MW =
1200 MW
Nuon is a leading energy company with customers in the Netherlands, Belgium and Germany for the purchase of electricity, gas, heat and supplemental services.
Nuon Magnum
IGCC Power Plant
COAL NATURAL GAS & BIOMASS

THE GREAT PLAINS SYNFUELS PLANT

The Gasification Plant shown in the foreground began Operating in 1984 in North Dakota & uses 6 million tons per year of Lignite Coal to Produce 54 Billion cubic feet of Synthetic Natural Gas (SNG) and 4 million tons per year of Carbon Dioxide used for EOR. The Antelope Valley Power Plant shown in the background uses 5 million tons of Lignite Coal for the two 440 MW Units.

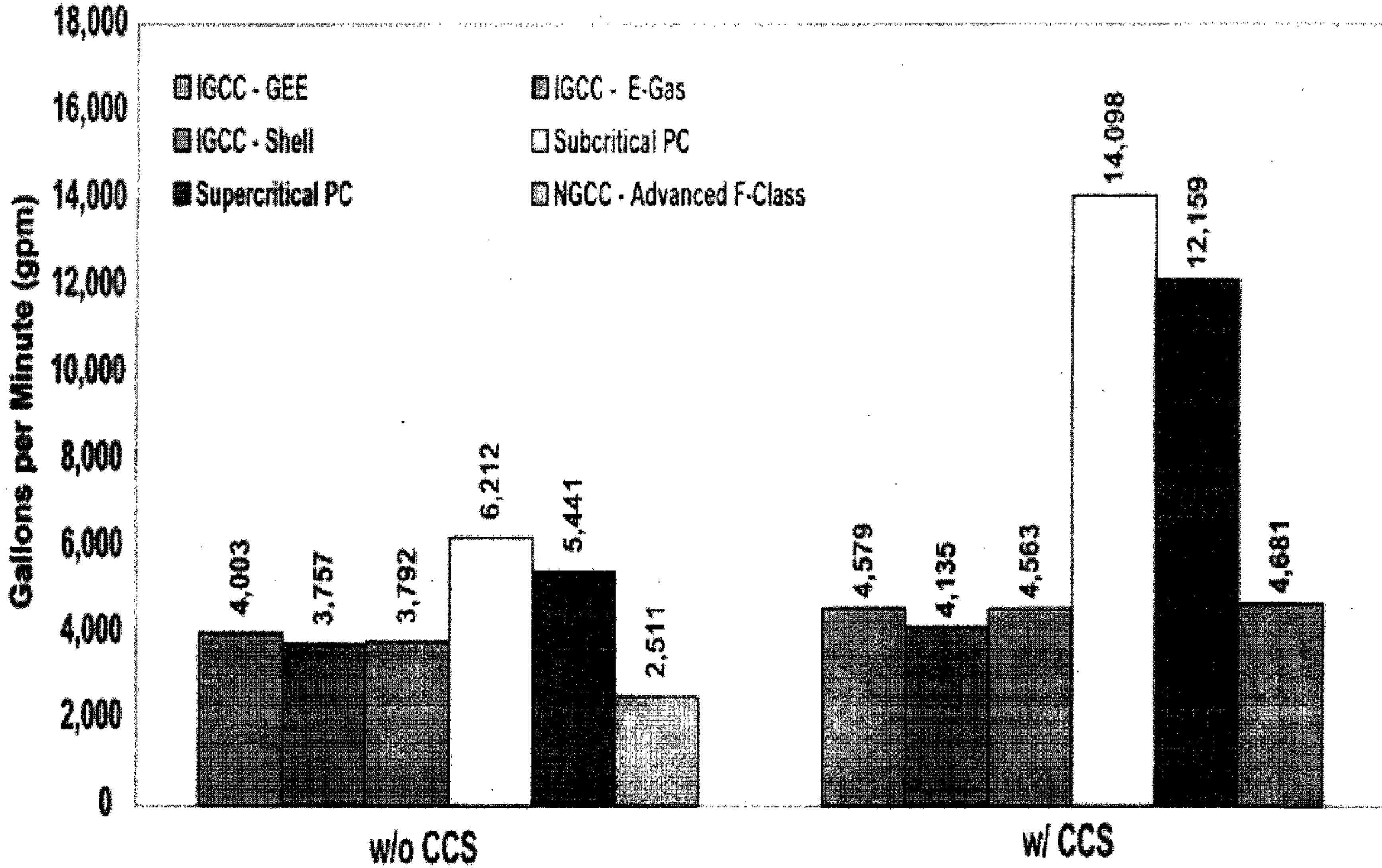


(Source: "The New Synfuels Energy Pioneers" by Stan Stelter, Introduction by Former President Jimmy Carter, published by Dakota Gasification Co.- 2001, A subsidiary of Basin Electric Power Cooperative, page 48)



(Source: Experience Gasifying ND Lignite by Al Lukes, Dakota Gasification Company, The Great Plains Synfuels Plant presented at the Montana Energy Future Symposium)

Figure 5. Plant Raw Water Usage



Source: "Fossil Energy Power Plant Desk Reference", DOE/NETL-2007/1282, May 2007, Overview-5, Figure 5.

Thermal Generation Technology Spectrum

	Conditions	Net Plant Efficiency	Net Plant Heat Rate (HHV)
Subcritical	2,400 psig 1,050 °F / 1,050 °F	35%	9,751 Btu/kWh
Subcritical HARP Cycle	2,400 psig 1,080 °F / 1,080 °F	37%	9,300 Btu/kWh
Supercritical	3,500 psig 1,050 °F / 1.075 °F	38%	8,981 Btu/kWh
Advanced Supercritical	Limit of 4,710 psig 1,130 °F / 1,165 °F / 1,165°F	42%	8,126 Btu/kWh
Ultra-Supercritical	5,500 psig 1,300 °F main steam	44%	7,757 Btu/kWh

Source: "Black & Veatch Supercritical Plant Technology Overview", by Ron Ott, Senior Vice President - Coal Program Director, presented at CSX Coal Forum, February 18-20, 2004.

Subcritical vs Supercritical Technology

	Subcritical	Supercritical
Number of Units	31	16
Average Age	17	20
Size Range	400 – 850 MW	400 – 850 MW
Average Size	565 MW	684 MW
Minimum Capacity Factor	50	50
Availability Factor	83.7	83.2
Forced Outage Rate	6.6	6.7
Capacity Factor	70.2	70.1

NERC GADS Data for 1994 – 1998 shows comparable reliability for supercritical and subcritical plants.

BLACK & VEATCH

Source: "Black & Veatch Supercritical Plant Technology Overview", by Ron Ott, Senior Vice President - Coal Program Director, presented at CSX Coal Forum, February 18-20, 2004.

Major Boiler Manufacturers

Boiler OEM	Recent Supercritical Units				
	Unit Name	Size (MW)	Location	COD	Steam Conditions
Alstom	Yunghung 1 & 2	800	Korea	2002	3,625 psig / 1,056 °F / 1,056 °F
	Niederaussem K	1,000	Germany	2002	3,916 psig / 1,076 °F / 1,112 °F
B&W	Millmerran 1&2	400	Australia	2002	3,596 psig / 1,054 °F / 1,105 °F
	Zimmer	1,300	USA	1991	3,480 psig / 1,000 °F / 1,000 °F
Babcock Hitachi	Hitachinaka 1	1,000	Japan	Planned for 2003	3,627 psig / 1,119 °F / 1,116 °F
	Tachibanawan	1,050	Japan	2000	3,770 psig / 1,121 °F / 1,135 °F
	Lippendorf F,S	933	Germany	2000	4,060 psig / 1,030 °F / 1,030 °F
FW	Taishan 1&2	710	China	Sold in 2002	3,770 psig / 1,009 °F / 1,043 °F
IHI	Hekinan 5	600	Japan	2002	3,625 psig / 1,059 °F / 1,104 °F
	Isogo 1	600	Japan	2002	4,060 psig / 1,021 °F / 1,135 °F
MHI	FP-1 2	600	Taiwan	1998	3,770 psig / 1,000 °F / 1,050 °F
	Hirono 5	600	Japan	2002	3,625 psig / 1,112 °F / 1,112 °F
Mitsui Babcock	Hemweg	680	Holland	1992	3,770 psig / 1,004 °F / 1,054 °F
	Meri Pori	560	Finland	1993	4,060 psig / 1,004 °F / 1,040°F

BLACK & VEATCH

Source: "Black & Veatch Supercritical Plant Technology Overview", by Ron Ott, Senior Vice President - Coal Program Director, presented at CSX Coal Forum, February 18-20, 2004.

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**

Direct Testimony of

David A. Schlissel

Synapse Energy Economics, Inc.

On Behalf of

Mark Trechock

and

Dakota Resource Council

PUBLIC VERSION

May 31, 2007

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LIST OF EXHIBITS

I. QUALIFICATIONS

Q. Mr. Schlissel, please state 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 the Dakota Resource Council.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government and utilities. A complete description of Synapse is available at our website, www.synapse-energy.com.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 28 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My recent clients have included the New Mexico Public Regulation Commission, the General Staff of the Arkansas Public Service Commission, the Staff of the Arizona Corporation Commission, the U.S. Department of Justice, the Commonwealth of Massachusetts, the Attorneys General of the States of Massachusetts, Michigan, New York, and Rhode Island, the General Electric Company, cities and towns in Connecticut, New York and Virginia, state consumer advocates, and national and local environmental organizations.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, Rhode Island, Wisconsin, Iowa, South Dakota, Georgia, Minnesota, Michigan and Florida and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

Q. Have you previously submitted testimony before this Commission?

A. No.

II. SUMMARY AND PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. Synapse was retained by the Dakota Resource Council to review the applications and supporting testimony and exhibits submitted by Otter Tail Power Company ("Otter Tail" or "OTP") and Montana-Dakota Utilities ("Montana-Dakota" or "MDU") and to evaluate whether the participation of these companies in the Big Stone II Generating Project is prudent. This testimony presents the results of our investigations of these issues. The Big Stone II Project would include a generating facility in South Dakota and transmission lines and associated facilities in South Dakota and Minnesota.

Q. Please summarize your conclusions.

A. A. Our conclusions are as follows:

1. OTP and Montana-Dakota have not adequately considered the risks associated with building a new coal-fired generating unit in their modeling analyses.

2. The most significant uncertainties and risks associated with the proposed Big Stone II Project are the potential for further increases in the project's capital cost; the potential for fuel supply disruptions that could affect plant operating performance; and fuel costs future restrictions on CO_2 emissions.

3. In particular, it is vitally important for OTP and Montana-Dakota to justify its participation in the Big Stone II Project in light of coming federal regulation of greenhouse gas emissions. It would be imprudent for each Company to continue its participation in the Project without doing so or by merely using a single set of very low CO_2 prices in such analyses. Instead, each Company should use a range of possible CO_2 prices such as the forecasts presented by Synapse in this proceeding.

4. OTP and Montana-Dakota have not shown that their demand for electricity cannot be met more cost effectively through alternatives including renewable energy resource, energy conservation and load-management measures than through the Big Stone II Project.

5. The economic and modeling analyses prepared by OTP and Montana-Dakota are biased in favor of the Big Stone II Project.

For these reasons, 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.

Q. Please explain how you conducted your investigations in this proceeding.

A. We have reviewed the testimony and exhibits filed by OTP and Montana-Dakota in this proceeding and by the Big Stone II Co-owners in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275 and in South Dakota Public Utilities Commission Case No. EL05-022. We also have reviewed the IRP filings made in Minnesota by OTP.

In addition, we have participated in discovery in this proceeding, the Minnesota Public Utilities Commission Dockets, the South Dakota Public Utilities Commission case, and the Minnesota IRP Dockets. As part of that work, we have prepared information requests that were submitted to OTP, Montana-Dakota, and the other Big Stone II Co-owners and have reviewed the responses to those information requests and to the discovery submitted by other parties including the Commission Staff in this proceeding, the Department of Commerce in Minnesota and the South Dakota Public Utilities Commission Staff in Case No. EL05-022.

Finally, we have rerun the Strategist model for Montana-Dakota.

Q. Please identify the Synapse staff who participated in these reviews of the Big Stone II Project.

A. Our reviews of the Big Stone II Project involved a collaborative group assessment. I was the Synapse project manager for these reviews. The other Synapse staff who participated in the reviews were Bruce Biewald, Anna Sommer, Dr. David White, Dr. Ezra Hausman, Lucy Johnston, Bob Fagan, Tim Woolf, and Michael Drunsic. Individually, and as a group, our project team has extensive experience and expertise in environmental, resource planning and related modeling analyses. Information on the other project team members is available on the Synapse website at www.synapse-energy.com/expertise/staff.shtml.

Q. Did you file testimony and testify in South Dakota Public Utilities Commission Case No. EL05-022?

A. Yes. I filed testimony on greenhouse gas regulation issues in Case No. EL05-022 on May 19, 2006 and testimony on other issues related to the proposed Big Stone II Project on May 26, 2006. In addition, I filed rebuttal and surrebuttal testimony on June 9 and June 22, 2006. I testified before the South Dakota Commission on June 29, 2006.

Q. Did you file testimony and testify in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275?

A. Yes. I filed testimony in Dockets Nos. CN-05-619 and TR-05-1275 on November 17 and 29, 2006 and testified on December 15 and 21, 2006.

III. OTP AND MONTANA-DAKOTA HAVE NOT ADEQUATELY CONSIDERED THE RISKS ASSOCIATED WITH BUILDING A NEW COAL-FIRED GENERATING UNIT

Q. Why is it important that OTP and Montana-Dakota consider risk when evaluating the economics of building the Big Stone II Project?

A. Risk and uncertainty are inherent in all enterprises. But the risks associated with any options or plans need to be balanced against the expected benefits from each such option or plan.

In particular, parties seeking to build new generating facilities and the associated transmission face of a host of major uncertainties, including, for example, the expected cost of the facility, future restrictions on emissions of carbon dioxide, and future fuel prices. The risks and uncertainties associated with each of these factors needs to be considered as part of the economic evaluation of whether to pursue the proposed facility or other alternatives.

Q. Have you seen any evidence that OTP and Montana-Dakota have adequately considered risks and uncertainties in the economic evaluations of the Big Stone II Project?

A. No. The OTP and Montana-Dakota modeling analyses that we have examined do not include any assessment of the uncertainty or risks associated with higher capital costs or regulation of greenhouse gas emissions. Instead, their models optimize for lowest costs based on a defined, predictable future.

For example, only the levelized analysis presented as Exhibit No. MR-2 by Mark Rolfes even attempts to present a break-even analysis for future CO_2 prices, one of the most important of the risks and uncertainties facing owners of proposed fossil-fired generating facilities. However, as I will discuss later in this testimony, that analysis is significantly flawed and its results cannot be relied upon.

Q. Is it reasonable to expect that OTP and Montana-Dakota could reflect uncertainty and risk in their economic analyses of whether to pursue the Big Stone II Project or alternatives?

A. Yes. There are a number of ways that OTP and Montana-Dakota could have considered uncertainty and risk. The most simple way would have been to perform sensitivity analyses reflecting engineering type bounding in which the key variables would be expected to vary by X% above or below their projected values. In my experience, utilities regularly consider risk in this way.

Q. Have OTP or Montana-Dakota previously performed any such sensitivity analyses regarding the proposed Big Stone II Project?

A. Yes. For example, OTP witness Morlock discussed in his Direct Testimony before the Minnesota Public Utilities Commission that under Minnesota law, Otter Tail Power was required to examine a number of alternate resource plan scenarios to satisfy regulatory requirements.[1] Consequently, Otter Tail Power had

1 Direct Testimony of Bryan Morlock, at pages 5 and 6.

examined scenarios involving base, low and high load growth with no, low and high externalities.

We believe that prudence also requires that OTP and Montana-Dakota look at fossil plant-specific uncertainties and risks associated with their proposal to build and operate the Big Stone II Project. This is especially true in light of the substantial cost increase in the estimated capital cost of the Big Stone II Project that was announced in July 2006.

Q. What are the most significant fossil plant-specific uncertainties and risks associated with the proposed Big Stone II Project?

A. The most significant uncertainties and risks associated with the proposed Big Stone II Project are the potential for further increases in the project's capital cost; the potential for fuel supply disruptions that could affect plant operating performance and fuel prices; and future restrictions on CO_2 emissions.

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 DSM also have some uncertainties and risks. These include potential capital cost escalation, contract uncertainty and customer participation uncertainty.

IV. OTP AND MONTANA-DAKOTA HAVE NOT ADEQUATELY CONSIDERED THE RISK OF FURTHER INCREASES IN THE ESTIMATED COST OF THE BIG STONE II PROJECT

Q. When did the Big Stone II Co-owners last increase the estimated cost of the Project?

A. The Big Stone II Co-owners announced a cost increase in August 2006, raising the estimated cost of the Project from about $1 billion to approximately $1.366 billion. This represented an increase of about $300 million, in 2011 dollars.

Q. Is it reasonable to expect that there will be no further increases in the estimated cost of the Big Stone II Project?

A. No. In their testimony before the Minnesota Public Utilities Commission, OTP and Montana-Dakota witnesses Rolfes and Trout identified a number of factors which have led to increases in the costs of building new power plants.

For example, Mr. Trout noted the following in his Supplemental Direct Testimony in Minnesota PUC Dockets Nos. CN-05-619 and TR-05-1275:

> 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 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.[2]

Mr. Rolfes identified the same factors as being responsible for the approximate $300 million increase in the estimated cost of building Big Stone II that was announced in August 2006.[3]

Q. Have other utilities similarly noted that the domestic U.S. and the worldwide competition for power plant design and construction resources, commodities, and manufacturing capacity have led to significant increases in power plant construction costs?

A. Yes. For example, in testimony filed at the North Carolina Utilities Commission on November 29, 2006, Duke Energy Carolinas emphasized the significant impact that the competition for the resources has been having on the costs of building new power plants. This testimony was presented to explain the approximate 47 percent, that is, $1 billion, increase in the estimated cost of Duke Energy Carolinas' proposed coal-fired Cliffside Project that the Company announced in October 2006.

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[2] 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.

[3] Applicants' Exhibit 32 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at pages 5 and 6.

In fact, Duke Energy Carolinas witness Judah Rose noted in his testimony to the North Carolina Utilities Commission that:

> 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.[4]

Mr. Rose further noted that the actual coal power plant capital costs as reported by plants already under construction exceed government estimates of capital costs by "a wide margin (i.e., 35 to 40 percent). Additionally, current announced power plants appear to face another increase in costs (i.e., approximately 40 percent addition."[5] Thus, according to Mr. Rose, new coal-fired power plant capital costs have increased approximately 90 to 100 percent since 2002.

Q. **Do you agree that with these reviews of the current market conditions affecting the costs of proposed coal-fired power plants like Big Stone II?**

A. Yes. These reviews of the factors affecting the estimated costs of new coal-fired generating facilities appears reasonable and are consistent with other information we have seen.

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[4] 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.

[5] Ibid, at page 6, lines 5-9, and page 12, lines 11-16.

Q. In their economic and modeling analyses of the Big Stone II Project, have OTP or Montana-Dakota assumed that there will be any further increases in the estimated cost of Big Stone II as a result of the same market conditions identified by Mr. Rolfes and Mr. Trout or other factors?

A. No.

Q. In your opinion, is that a prudent assumption, that is, that there will not be any further increases in the capital cost of the Big Stone II Project before it is completed?

A. No. Although the current project cost estimate does increase some contingencies, we believe that given past history of large construction projects, it is reasonable to assume that the actual cost of building the Big Stone II Project may be higher than the current cost estimate. This is especially true because all project bids have not been let and construction has not even started.

Indeed, even Mr. Rolfes and Mr. Trout do not foreclose the potential for further increases in the Project's estimated capital cost. For example, Mr. Rolfes has testified in Minnesota that "the [current project] price estimate is a dynamic number and there remains the possibility for design changes."[6] Any significant design changes could have an impact, resulting in capital cost increases or decrease.[7]

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.[8] Mr. Trout has further noted that "the Big Stone II Co-owners have not been in a position realistically or

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6 Applicants' Exhibit 32 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at page 4, lines 7-10.

7 Ibid.

8 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.

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."[9]

Q. Have you seen any specific evidence that shows that the estimated cost of the Big Stone II Project, in fact, already has increased above the Co-owners' current official public estimate?

A. Yes. At a late August 2006 project owners meeting, the CEOs of the Big Stone II Co-owners adopted a plan to minimize their cost exposure until all of the various permits for the Project are approved.[10] By adopting this spending limitation plan, the Co-owners expected to reduce their short-term spending on the Big Stone II Project and, consequently, their financial exposure. To do they suspended all engineering work and equipment procurements until mid-2007 and required that the equipment bids that had been received be rebid.[11]

An October 2006 Black & Veatch report described the work that would be allowed under the new project plan:

> This is the case which was selected by the CEOs after the August 2006 E&O meeting. This case reflects that, in general, only tasks required to support permitting will be performed prior to the [October 1, 2007] significant financial commitment (SFC) date, except that the [project team] staff would remain intact to maintain project continuity. The [Black & Veatch] team would be disbanded. The 'early five' procurements would each be rebid, with the bid issue documents being prepared before the SFC date and issued to the bidders as soon as possible after the SFC date.[12]

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

10 *Financial Risk Commitments Prior to Receiving the MN CON*, prepared by Black & Veatch, October 19, 2006, provided in response to MCEA IRs Nos. 214-216, at Bates Page Numbers JCO0012380-JCO00012397.

11 Ibid, at page no. 1-1, Bates Page Number JCO0012381.

Q. Does it appear that this plan was implemented?

A. Yes. Project documents indicate that meetings were held in September to discuss the work that Black & Veatch would undertake prior to and during the project suspension.

Q. What was the estimated impact of the adoption of this revised short-term spending and financial exposure plan on the expected commercial operation date of the Big Stone II Project?

A. The project documents reveal that the adoption of this plan was expected to push the actual commercial operation date for the Big Stone II Project to July 1, 2013.[13] However, according to Black & Veatch, even this late date did not reflect any possible schedule impacts associated with changes in equipment lead times, labor availability, rescheduling or construction inefficiencies due to winter weather, or other market conditions.[14]

Q. What was the estimated impact of the adoption of this revised short-term spending and financial exposure plan on the estimated capital cost of the Big Stone II Project?

A. The purpose of the spending limitation plan adopted by the Co-owners in late August 2006 was to limit project expenditures in the short-term and, hence, the Co-owners' financial exposure, until the PSD air permit and Minnesota Certificate of Necessity are received. However, Black & Veatch estimated that the adoption of this short-term plan would increase the ultimate cost of the Big Stone

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12 Ibid, at page 4-5, Bates Page Number JCO0012388.

13 Ibid, at page 4-6, Bates Page Number JCO0012389.

14 Ibid.

II Project by approximately $199 million. This $199 million figure reflected escalation at 6% plus additional project team and Black & Veatch staff costs.[15]

But, even this figure does not reflect other factors that could lead to an increase in the ultimate cost of the Big Stone II Project. These factors could include the possibility that equipment bidders will raise their prices during the rebidding process. This was something that the Big Stone II project team was told during bidder interviews. Other factors that could lead to higher project costs include further project delays, changes in equipment lead times, labor availability, rescheduling or construction inefficiencies due to winter weather, or other market conditions.

Q. **Just to be clear, is the $199 million estimated increase in the ultimate Project cost due to the short-term spending limitation plan adopted by the Big Stone II Co-owners in late August would be in addition to or on top of the capital cost increase that was announced earlier that month?**

A. Yes. The estimated $199 million cost increase resulting from the late August decision by the Big Stone II Co-owners is above or in addition to the $1.366 billion cost estimate announced by the Co-owners in July 2006.

Q. **Have you seen any evidence that OTP or Montana-Dakota have reflected this additional $199 million cost increase in any Big Stone II Project economic or modeling analyses?**

A. No.

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15 *Owners' Alternatives for Financial Risk Commitments Prior to CON and PSD*, prepared by Black & Veatch, August 24, 2006, provided in response to MCEA IRs Nos. 214-216, at page 3-6, Bates Page Number JCO0012332.

Q. Have OTP or Montana-Dakota assumed in their economic and modeling analyses that the actual commercial operation date for the Big Stone II Project will be delayed beyond 2011?

A. No. Otter Tail Power has continued to assume a commercial date of January 1, 2011 for the Big Stone II Project.

Q. Did Black & Veatch ask the Big Stone II Co-owners to reconsider their short-term spending plan?

A. Yes. Black & Veatch asked the Big Stone II Co-owners to reconsider their earlier decision and to lift the short-term project suspension plan they adopted in August 2006. This would raise project spending, and, consequently, the Co-owners' financial exposure, prior to September 2007 by approximately $170 million.[16]

According to Black & Veatch, revising the short-term plan in this way could enable the project to achieve a commercial operation date of May 2012, instead of July 2013.[17] Also revising the short-term plan in this way, could limit the effect of the short-term spending limits on the ultimate Project cost to $60 million instead of $199 million impact.[18] This would still mean that the current capital cost estimate for the Big Stone II Project is higher than the publicly announced $1.366 million cost estimate.

Q. Have the Big Stone II Co-owners approved this request?

A. It is unclear what action the Big Stone II Co-owners took on this request. It appeared that the Co-owners were going to vote on the Black & Veatch request for reconsideration at a meeting on November 30, 2006. But it is uncertain whether they did so.

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16 Ibid., at page 4-2, Bates Page Number JCO0012385.

17 Ibid. at page 4-4, Bates Page Number JCO0012387.

18 Ibid. at page 4-4, Bates Page Number JCO0012387.

Q. Is it reasonable to expect that there could be further increases in the cost of the Big Stone II Project?

A. Yes. During the remaining six or seven years before the Project is completed, if indeed it is allowed to continue, any number of factors could lead to even higher costs. These factors could include additional delays, additional regulation-related costs, market conditions and weather conditions. Thus, there is no guarantee that the current capital cost estimate for the Big Stone II Project will be the last, even if it is increased by another $199 million to reflect the impact of the short-term spending limitations adopted by the Big Stone II Co-owners in late August 2006.

Q. Is it your testimony that OTP and Montana-Dakota should change their current cost estimate for the Big Stone II Project?

A. Clearly, OTP and Montana-Dakota should revise their economic and modeling to reflect the impact of the short-term spending limitation plan adopted by the Co-owner CEOs back in August 2006. In addition, given that there is significant uncertainty in the current cost estimate for the Project, OTP and Montana-Dakota should perform sensitivity analyses to reflect further increases in the Project's capital cost.

Q. Have you seen any utilities that have prepared such sensitivity analyses to reflect increases in the estimated Project capital costs?

A. Yes. In its modeling of the proposed coal-fired Cliffside Project, Duke Energy Carolinas has considered some scenarios reflecting a 20 percent higher coal capital cost. Unfortunately, Duke combined this 20 percent higher coal capital cost with higher coal and natural gas prices which distorted the analysis and masked the impact of the higher coal capital cost by including the mostly unrelated higher natural gas prices.[19] However, Duke still did consider a 20 percent higher coal capital cost.

19 Duke's 2005 Annual Plan filing, at page 49.

Q. Have you seen any such capital cost sensitivity analyses that have been prepared by OTP or Montana-Dakota?

A. Yes. The September 2005 *Analysis of Baseload Generation Alternatives* prepared for the Big Stone II Co-owners by Burns & McDonnell examined a number of sensitivity analyses including a plus or minus 10 percent of the estimated project capital cost.[20] However, we are not aware or have we seen any similar capital cost sensitivities being performed in subsequent analyses by OTP or Montana-Dakota, particularly those prepared since the current Big Stone II capital cost estimate was announced in August 2006.

Q. Do you agree with the testimony of OTP and Montana-Dakota witnesses Rolfes and Trout that these same market conditions also have led to increases in the estimated costs of other supply-side alternatives such as wind and natural gas-fired facilities?[21]

A. Yes. In general we agree with Mr. Rolfes and Mr. Trout's testimony that these same market conditions also have led to increases in the estimated costs of other supply-side options.

However, there are several factors which suggest that the impact of these factors might be greater on coal-fired facilities than on other alternatives. First, as Mr. Trout has testified in Minnesota, coal-fired plants do require more labor hours during construction than the other technologies – a comparably sized combined cycle project would require substantially fewer labor hours to construct.[22]

Second, Black & Veatch has noted that the factors which have led to increased coal plant capital costs "generally apply to all power generation technology

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[20] Included as Exhibit No. MR-1 to the testimony of Mark Rolfes.

[21] Applicants' Exhibit 32 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, , at page 8, line 21, to page 9, line 10, and Applicants' Exhibit 33, at page 28, line 17, to page 29, line 14.

[22] Applicants' Exhibit 33 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275,, at page 29, lines 17-21.

capital costs.[23] However, Black & Veatch further explained that simple cycle and combined cycle equipment costs have remained steady because the demand for combustion turbines "is relatively low."[24]

V. OTP AND MONTANA-DAKOTA HAVE NOT ADEQUATELY CONSIDERED THE RISKS ASSOCIATED WITH THE POTENTIAL FOR FUEL SUPPLY DISRUPTIONS OR HIGHER FUEL COSTS

Q. What average annual capacity factors do OTP and Montana-Dakota assume the Big Stone II Project will be able to achieve?

A. Generally, the Big Stone II Co-owners project an 88 percent average annual capacity factor for Big Stone II.

Q. Is this a reasonable assumption?

A. It is a very optimistic assumption to assume that a plant that has not yet started commercial operations or, indeed, is not even under construction, will achieve such a high capacity factor in every year, especially during the plant's early immature "breaking-in" years of operation. However, it is not unreasonable to assume that a new base load coal-fired facility, if prudently managed and maintained, ultimately could be able to achieve relatively similar operating performance during its mature operating years.

Q. Are there any factors, besides imprudent management or maintenance, that could result in the plant's failing to achieve the projected 88 percent capacity factor?

A. Yes. New coal-fired facilities, like Big Stone II, may be subject to some of the same production and coal-deliverability problems that have recently plagued existing coal-fired units throughout the Midwest that depend on coal supplies

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[23] August 2006, *Otter Tail Power Company Supply-Side Technology Study Update*, prepared by Black & Veatch, at page 1-2, Bates Page Number OTP0006341, provided in response to MCEA IR No. 174 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275.

[24] Ibid.

from the Powder River Basin. Such problems could adversely affect the reliability of Big Stone II and its ability to operate at a consistent 88 percent average annual capacity factor.

Q. Could such production and deliverability problems also affect the prices of the coal that would be burned at Big Stone II?

A. Yes.

Q. Have OTP or Montana-Dakota prepared any sensitivity analyses as part of their recent modeling to determine whether higher than expected coal prices and/or less than optimal plant performance due to coal deliverability problems would affect the overall economics of the Big Stone II Project?

A. OTP and Montana-Dakota have not prepared any such sensitivity analyses that we have seen. Remarkably, the Big Stone II Co-owners, including OTP and Montana-Dakota have refused to even acknowledge that future coal shortage issues (caused by rail and/or production issues) *may* diminish Big Stone II's reliability.[25] They similarly refused to acknowledge that recent coal shortage issues *may* increase the risk associated with developing the Big Stone II power plant.[26]

Indeed, problems with the delivery of coal have already caused a significant interruption in the operation of Big Stone I last year. For several weeks in 2006, according to media reports,[27] the plant had to scale back operations to 45% of its capacity. Big Stone Plant Manager Jeff Endrizzi said, about the period of reduced production, "It was a very tough 54 days for us but we're here to produce as much

25 Big Stone II Co-owner responses to Questions Nos. 5 and 39 of the South Dakota Commission Staff's Third Data Request in South Dakota Public Utilities Commission Case No. EL05-022.

26 Big Stone II Co-owner responses to Questions No. 38 of the South Dakota Commission Staff's Third Data Request in South Dakota Public Utilities Commission Case No. EL05-022.

27 "Coal Supply Still Uncertain at Big Stone," Keloland Television broadcast, 5/25/2006. Online at http://keloland.com/NewsDetail6162.cfm?Id=0,48308. See also, "Big Stone Plant Doesn't Have Enough Coal," Keloland Television broadcast, 03/20/2006, Online at http://keloland.com/NewsDetail6162.cfm?Id=0,46855.

power as we can and to not be able to do that is very uncomfortable." He also noted that "I think just raising the general level of awareness of the situation can't hurt. It's hitting us here directly, locally, but it's a very broad based problem."

Q. Is it prudent to not even consider the potential for coal shortages as a risk associated with developing the Big Stone II Project?

A. No. Given the serious deliverability problems that have been experienced with coal from the Powder River Basin since May 2005 and the disputes that have arisen between coal shippers, utilities and the railroads that deliver coal from the Powder River Basin, it is not prudent to ignore this risk when evaluating the economics of proposed coal-fired facilities like the Big Stone II Project. Some utilities have been forced to import coal from Columbia in South America or as far away as Indonesia.

Q. Have any of the economic analyses prepared for the Big Stone II Co-owners contained any sensitivities to reflect the potential for higher fuel prices and/or lower than projected operating performance?

A. Yes. The September 2005 *Analysis of Baseload Generation Alternatives*, prepared by Burns & McDonnell, did prepare sensitivity analyses reflecting changes in the assumed fuel prices and capacity factors.[28] However, OTP and Montana-Dakota have not prepared similar sensitivity analyses as part of their more recent Big Stone II Project modeling that reflects the increase in the estimated capital cost that was announced in 2006.

[28] Exhibit No. MR-1 to the testimony of Mark Rolfes.

VI. OTP AND MONTANA-DAKOTA HAVE NOT CONSIDERED THE RISKS ASSOCIATED WITH FUTURE FEDERALLY MANDATED GREENHOUSE GAS REDUCTIONS

VI.A. FEDERALLY MANDATED GREENHOUSE GAS REDUCTIONS CAN BE EXPECTED IN THE NEAR FUTURE

Q. Is it prudent to expect that a policy to address climate change will be implemented in the U.S. in a way that should be of concern to coal-dependent utilities in the Midwest?

A. Yes. The prospect of global warming and the resultant widespread climate changes has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the United Nations Framework Convention on Climate Change ("UNFCCC"), a treaty that the U.S. ratified in 1992, along with almost every other country in the world. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions of industrialized nations and economies in transition.

Despite being the single largest contributor to global emissions of greenhouse gases, the United States remains one of a very few industrialized nations that have not signed the Kyoto Protocol.[29] Nevertheless, individual states, regional groups of states, shareholders and corporations are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon, though not yet successful, have gained ground in recent years. These developments, combined with the growing scientific understanding of, and evidence of, climate change as outlined

[29] As we use the terms "carbon dioxide regulation" and "greenhouse gas regulation" throughout our testimony, there is no difference. While we believe that the future regulation we discuss here will govern emissions of all types of greenhouse gases, not just carbon dioxide ("CO2"), for the purposes of our discussion we are chiefly concerned with emissions of carbon dioxide. Therefore, we use the terms "carbon dioxide regulation" and "greenhouse gas regulation" interchangeably. Similarly, the terms "carbon dioxide price," "greenhouse gas price" and "carbon price" are interchangeable.

in Dr. Hausman's testimony, mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time. The question is not whether the United States will develop a national policy addressing climate change, but when and how. The electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector's contribution to national emissions and the comparative ease of regulating large point sources.

There are, of course, important uncertainties with regard to the timing, the emission limits, and many other details of what a carbon policy in the United States will look like.

Q. If there are uncertainties with regard to such important details as timing, emission limits and other details, why should a utility engage in the exercise of forecasting greenhouse gas prices?

A. First of all, utilities are implicitly assuming a value for carbon allowance prices whether they go to the effort of collecting all the relevant information and create a price forecast, or whether they simply ignore future carbon regulation. In other words, a utility that ignores future carbon regulations is implicitly assuming that the allowance value will be zero. The question is whether it's appropriate to assume zero or some other number. There is uncertainty in any type of utility forecasting and to write off the need to forecast carbon allowance prices because of the uncertainties is not prudent.

For example, there are myriad uncertainties that utility planners have learned to address in planning. These include randomly occurring generating unit outages, load forecast error and demand fluctuations, and fuel price volatility and uncertainty. These various uncertainties can be addressed through techniques such as sensitivity and scenario analyses.

To illustrate that there is significant uncertainty in other types of forecasts, we think it is informative to examine historical gas price forecasts by the Energy Information Administration (EIA). Exhibit DAS-2 compares EIA forecasts from the period 1990 - 2006 with actual price data through 2005. The data, over more than a decade, shows considerable volatility, even on an annual time scale.[30] But the truly striking thing that jumps out of the figure is how wrong the forecasts have sometimes been. For example, the 1996 forecast predicted gas prices would start at $2.61/MMBtu and remain under $3/MMBTU through 2010, but by the year 2000 actual prices had already jumped to $4.82/MMBTu and by 2005 they were up to $8.09/MMBtu.

In view of the forecasting track record for gas prices one might be tempted to give up, and either throw darts or abandon planning altogether. But thankfully modelers, forecasters, and planners have taken on the challenge – and have improved the models over time, thereby producing more reliable (although still quite uncertain) price forecasts, and system planners have refined and applied techniques for addressing fuel price uncertainty in a rational and proactive way.

It is, therefore, troubling and wrong to claim that forecasting carbon allowance prices should not be undertaken as a part of utility resource decision-making because it is "speculative."

Q. Do Montana-Dakota and OTP have any opinions or thoughts as to when carbon regulation will happen?

A. No. Interrogatory 18 of Joint Intervenors' First Set and First Amended Set of Interrogatories in South Dakota Public Utilities Commission Case No. EL05-022 asked each of the Co-owners to state whether it:

> believes it is likely that greenhouse gas regulation (ghg) will be implemented in the U.S. (a) in the next five years, (b) in the next ten years, and (c) in the next twenty years.[31]

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30 Gas prices also show terrific volatility on shorter time scales (e.g., monthly or weekly prices).

31 Big Stone II Co-owners' response to Interrogatory 18 in South Dakota Public Utilities Commission Case No. EL05-022.

None of the Co-owners, including OTP and Montana-Dakota, had any thoughts as to when or even if greenhouse gas regulation would occur.

Q. If the Big Stone II Project were to be built, is carbon regulation an issue that could be reasonably dealt with in the future, once the timing and stringency of the regulation is known?

A. Unfortunately, no. Unlike for other power plant air emissions like sulfur dioxide and oxides of nitrogen, there currently is no commercial or economical method for post-combustion removal of carbon dioxide from supercritical pulverized coal plants. The Big Stone II Co-owners agree on that point. During the public hearing in South Dakota Public Utilities Commission Case No. EL05-022 that was held in Milbank, South Dakota on September 13, 2005, the Co-owners presented several slides on the expected combined emissions from Big Stone Units I & II. The descriptive slide for the CO_2 emissions chart submitted to the South Dakota PUC states there is "no commercially available capture and sequestration technology." This slide is attached as Exhibit DAS-3. Regardless of the uncertainty, this is an issue that needs to be dealt with before new resource decisions are made and before transmission lines are constructed to enable generation at those new resources.

Even if such technology were available, there is no indication that Montana-Dakota or OTP have evaluated the possibility for carbon sequestration at or near the Big Stone site nor the economics of carbon capture at Big Stone Unit II.

Q. Do other utilities have opinions about whether and when greenhouse gas regulation will come?

A. Yes. A number of utility executives have argued that mandatory federal regulation of the emissions of greenhouse gases is inevitable.

For example, in April 2006, the Chairman of Duke Energy, Paul Anderson, stated:

> From a business perspective, the need for mandatory federal policy in the United States to manage greenhouse gases is both urgent and

> real. In my view, voluntary actions will not get us where we need to be. Until business leaders know what the rules will be – which actions will be penalized and which will be rewarded – we will be unable to take the significant actions the issue requires.[32]

Similarly, James Rogers, who was the CEO of Cinergy and is currently CEO of Duke Energy, has publicly said "[I]n private, 80-85% of my peers think carbon regulation is coming within ten years, but most sure don't want it now."[33] Mr. Rogers also was quoted in a December 2005 *Business Week* article, as saying to his utility colleagues, "If we stonewall this thing [carbon dioxide regulation] to five years out, all of a sudden the cost to us and ultimately to our consumers can be gigantic."[34]

Not wanting carbon regulation from a utility perspective is understandable because carbon price forecasting is not simple and easy, it makes resource planning more difficult and is likely to change "business as usual." For many utilities, including the Big Stone II Co-owners, that means that it is much more difficult to justify building a pulverized coal plant. Regardless, it is imprudent to ignore the risk.

Duke Energy is not alone in believing that carbon regulation is inevitable and, indeed, some utilities are advocating for mandatory greenhouse gas reductions. In a May 6, 2005, statement to the Climate Leaders Partners (a voluntary EPA-industry partnership), John Rowe, Chair and CEO of Exelon stated, "At Exelon, we accept that the science of global warming is overwhelming. We accept that limitations on greenhouse gases emissions [sic] will prove necessary. Until those

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32 Paul Anderson, Chairman, Duke Energy, "Being (and Staying in Business): Sustainability from a Corporate Leadership Perspective," April 6, 2006 speech to CERES Annual Conference, at: http://www.duke-energy.com/news/mediainfo/viewpoint/PAnderson_CERES.pdf

33 "The Greening of General Electric: A Lean, Clean Electric Machine," *The Economist*, December 10, 2005, at page 79.

34 "The Race Against Climate Change," *Business Week*, December 12, 2005, online at http://businessweek.com/magazine/content/05_50/b3963401.htm.

limitations are adopted, we believe that business should take voluntary action to begin the transition to a lower carbon future."

In fact, several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs into their long term planning, and have set specific agendas to mitigate shareholder risks associated with future U.S. carbon regulation policy. These utilities cite a variety of reasons for incorporating risk of future carbon regulation as a risk factor in their resource planning and evaluation, including scientific evidence of human-induced climate change, the U.S. electric sector's contribution to emissions, and the magnitude of the financial risk of future greenhouse gas regulation.

Duke Energy and FPL Group are participating in the high profile U.S. Climate Action Partnership ("USCAP") which advocates for federal, mandatory legislation of greenhouse gases. The six principles of this group are:

- Account for the global dimensions of climate change;
- Create incentives for technology innovation;
- Be environmentally effective;
- Create economic opportunity and advantage;
- Be fair to sectors disproportionately impacted; and
- Reward early action.[35]

Most significantly, USCAP has argued that CO_2 emissions should be reduced by 60% to 80% by 2050. As I will discuss later, this is relatively the same goal as many of the climate change bills that have been introduced in the current U.S. Congress.[36]

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35 www.us-cap.org.

36 *A Call for Action*, at page 7, available at www.us-cap.org.

Some of the companies believe that there is a high likelihood of federal regulation of greenhouse gas emissions within their planning period. For example, Pacificorp states a 50% probability of a CO_2 limit starting in 2010 and a 75% probability starting in 2011. The Northwest Power and Conservation Council models a 67% probability of federal regulation in the twenty-year planning period ending 2025 in its resource plan. Northwest Energy states that CO_2 taxes "are no longer a remote possibility."[37]

Even those in the electric industry who oppose mandatory limits on greenhouse gas regulation believe that regulation is inevitable. David Ratcliffe, CEO of Southern Company, a predominantly coal-fired utility that opposes mandatory limits, said at a March 29, 2006, press briefing that "There certainly is enough public pressure and enough Congressional discussion that it is likely we will see some form of regulation, some sort of legislation around carbon."[38]

Q. Why would electric utilities, in particular, be concerned about future carbon regulation?

A. Electricity generation is very carbon-intensive. Electric utilities are likely to be one of the first, if not the first, industries subject to carbon regulation because of the relative ease in regulating stationary sources as opposed to mobile sources (automobiles) and because electricity generation represents a significant portion of total U.S. greenhouse gas emissions. A new generating facility may have a book life of twenty to forty years, but in practice, the utility may expect that that asset will have an operating life of 50 years or more. By adding new plants, especially new coal plants, a utility is essentially locking-in a large quantity of carbon dioxide emissions for decades to come. In general, electric utilities are increasingly aware that the fact that we do not currently have federal greenhouse

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37 Northwest Energy 2005 Electric Default Supply Resource Procurement Plan, December 20, 2005; Volume 1, p. 4.

38 Quoted in "U.S. Utilities Urge Congress to Establish CO2 Limits," Bloomberg.com, http://www.bloomberg.com/apps/news?pid=10000103&sid=a75A1ADJv8cs&refer=us

gas regulation is irrelevant to the issue of whether we will in the future, and that new plant investment decisions are extremely sensitive to the expected cost of greenhouse gas regulation throughout the life of the facility.

Q. Do others in the private sector, besides electric utilities, also believe that regulation of greenhouse gases is inevitable?

A. Yes. Corporate leaders, investors, financial analysts and major corporations are increasingly anticipating and preparing for requirements to reduce greenhouse gas emissions.[39] For example, a recent survey of 31 multinational corporations by the Pew Center on Global Climate Change found that 90 percent expect the U.S. government to set standards for greenhouse gas emissions imminently.[40] About 18 percent believe that federal standards will take effect before 2010: another 67 percent believe those standards will take effect between 2010 and 2015.[41]

Investors and investment analysts also are anticipating the imminent establishment of federally mandated reductions in greenhouse gas emissions. For example, in October 2004, Fitch Ratings reported that over the next ten years, it expected that:

> the power industry to face higher environmental standards for sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury, as well as new rules for the emissions of greenhouse gases (GHGs). As the scientific debate has moved from the topic of "whether global warming exists) to a discussion of the magnitude of the problem, concerns about GHGs have expanded to a wider audience. Investors and insurance companies are becoming increasingly concerned about the financial effects of future environmental regulations on the power sector as a primary emitter of GHGs. Requirements to control the sources of global warming and enhanced regulation of other pollutants could increase the financial

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39 Exhibit DAS-4, at pages 23-26.

40 http://www.pewclimate.org/docUploads/PEW%5FCorpStrategies%2Epdf, at page 1.

41 Ibid.

> liability of coal-dependent power producers, thereby leading to lower returns and lower post-investment cash generation.[42]

Fitch Ratings has more recently been quoted as telling industry representatives that it believes that a federal law to cap CO_2 emissions is "imminent" and that "compliance costs could have a significant effect on the credit profiles of generators."[43]

Q. Have mandatory greenhouse gas emissions reductions programs begun to be examined and debated in the U.S. federal government?

A. To date, the U.S. government has not required greenhouse gas emission reductions. However, a number of legislative initiatives for mandatory emissions reduction proposals have been introduced in Congress. 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. Through their consideration of these proposals, legislators are increasingly educated on the complex details of different policy approaches, and they are laying the groundwork for a national mandatory program. Some of the federal proposals that would require greenhouse gas emission reductions that had been submitted in Congress through early February 2007 are summarized in Table 1 below.

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42 *Status of Environmental Regulation*, Fitch Ratings Corporate Finance, October 12, 2004.

43 *CO2 Trading Plan could cost US utilities $6bil/year: Fitch*, Platts, 7Nov2006,

Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in Congress[44]

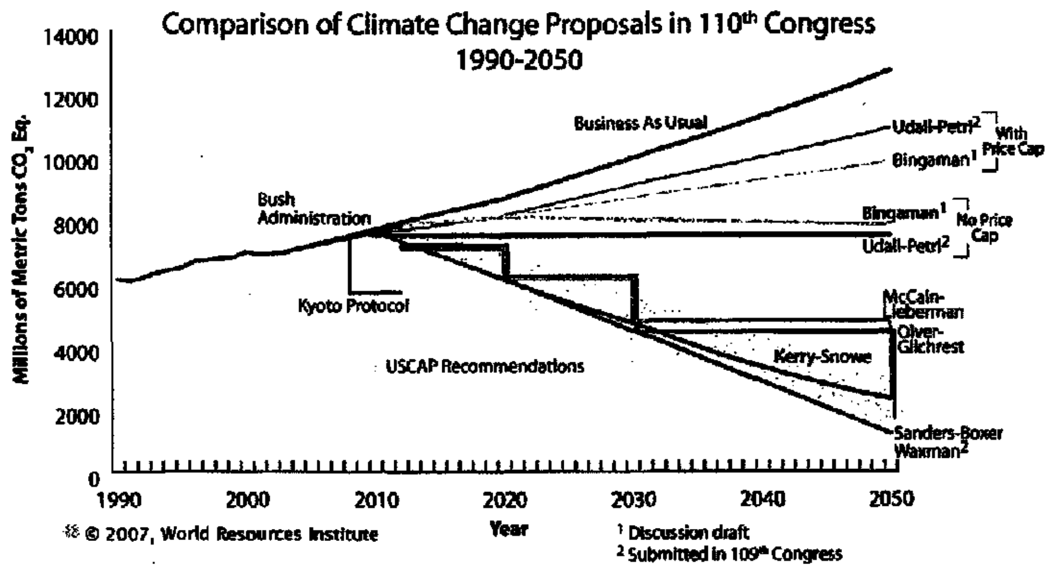
Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources
McCain Lieberman S 1151	Climate Stewardship and Innovation Act	2005	Cap at 2000 levels	Economy-wide, large emitting sources [CHECK]
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants > 15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO_2) starting in 2009, 2001 levels (2.454 billion tons CO_2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Energy and energy-intensive industries
Carper S.2724	Clean Air Planning Act	2006	2006 levels by 2010, 2001 levels by 2015	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Kerry and Snowe S.4039	Global Warming Reduction Act	2006	No later than 2010, begin to reduce U.S. emissions to 65% below 2000 levels by 2050	Not specified

44 More detailed summaries of the bills that have been introduced in the U.S. Senate in the 110th Congress are presented in Exhibit DAS-5.

Waxman H.R. 5642	Safe Climate Act	2006	2010 – not to exceed 2009 level, annual reduction of 2% per year until 2020, annual reduction of 5% thereafter	Not specified
Jeffords S. 3698	Global Warming Pollution Reduction Act	2006	1990 levels by 2020, 80% below 1990 levels by 2050	Economy-wide
Feinstein- Carper S.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	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
Sen. Bingaman – Discussion draft		As of 1/11/2007	2.6%/year reduction in emissions intensity from 2012-2021, 3%/year reduction starting in 2022	Economy-wide

The reductions that the bills that have been introduced in the current U.S. Congress would mandate are illustrated in Figure 1 below.

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



Q. Is it reasonable to believe that the potential for passage of greenhouse gas regulations have improved as a result of last November's federal elections?

A. Yes. Although there are increasing numbers of Republican legislators who recognize the need for legislation to regulate the emissions of greenhouse gases, the results of the recent elections, in which control of both Houses of Congress shifted to Democrats, are likely to improve the chances for near-term passage of significant legislation. For example, experts at an industry conference right after the elections expressed the opinion that now that Democrats have won control of Congress, electric utilities should expect a strong legislative push for mandatory caps on carbon dioxide emissions.[45]

Senator McCain also has indicated that he believed that the chances of Congress approving meaningful global warming legislation before 2008 were "pretty good"

[45] *Mandatory US carbon caps coming following elections: observers*, Platts 9Nov2006.

and that he believed that "we've reached a tipping point in this debate, and its long overdue."[46]

At the same time, Senators Bingaman, Boxer and Lieberman sent a letter to President Bush on November 14, 2006, seeking the President's commitment to work with the new Congress to pass meaningful climate change legislation in 2007.[47] Senators Bingaman, Boxer and Lieberman in January are the chairpersons of, respectively, the Senate Energy and Natural Resources Committee, the Senate Environment and Public Works Committee and the Senate Homeland Security and Governmental Affairs Committee in the current Congress.

Nevertheless, our conclusion that significant greenhouse gas regulation in the United States is inevitable is not based on the results of any single election or on the fate of any single bill introduced in Congress.

Q. Have recent polls indicated that the American people are increasingly in favor of government action to address global warming concerns?

A. Yes. A summer 2006 poll by Zogby International showed that an overwhelming majority of Americans are more convinced that global warming is happening than they were even two years ago, and they are also connecting intense weather events like Hurricane Katrina and heat waves to global warming.[48] Indeed, the poll found that 74% of all respondents, including 87% of Democrats, 56% of Republicans and 82% of Independents, believe that we are experiencing the effects of global warming.

The poll also indicated that there is strong support for measures to require major industries to reduce their greenhouse gas emissions to improve the environment

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[46] Ibid.
[47] Ibid.
[48] "Americans Link Hurricane Katrina and Heat Wave to Global Warming," Zogby International, August 21, 2006, available at www.zogby.com/news.

without harming the economy – 72% of likely voters agreed such measures should be taken.[49]

Other recent polls reported similar results. For example, a Time/ABC/Stanford University poll issued in the spring found 68 percent of Americans are in favor of more government action.[50] In addition, a September 2006 telephone poll, conducted by NYU's Brademas Center for the Study of Congress, reported that 70% of those polled stated that they were worried about global warming.[51]

At the same time, according to a recent public opinion survey for the Massachusetts Institute of Technology, Americans now rank climate change as the country's most pressing environmental problem—a dramatic shift from three years ago, when they ranked climate change sixth out of 10 environmental concerns.[52] Almost three-quarters of the respondents felt the government should do more to deal with global warming, and individuals were willing to spend their own money to help.

VI.B. STATE AND REGIONAL ACTION

Q. Are any states developing and implementing climate change policies that will have a bearing on resource choices in the electric sector?

A. Yes. States continue to be the leaders and innovators in developing and implementing policies that will affect greenhouse gas emissions.

On August 30, 2006, Governor Schwarzenegger and the California Legislature reached an agreement on AB32, the Global Warming Solutions Act.[53] The Act

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49 Ibid.

50 "Polls find groundswell of belief in, concern about global warming." Greenwire, April 21, 2006, Vol. 10 No. 9. See also Zogby's final report on the poll which is available at http://www.zogby.com/wildlife/NWFfinalreport8-17-06.htm.

51 Kaplun, Alex: "Campaign 2006: Most Americans 'worried' about energy, climate;" Greenwire, September 29, 2006.

52 *MIT Carbon Sequestration Initiative, 2006 Survey,* http://sequestration.mit.edu/research/survey2006.html

53 Governor Schwarzenegger press release, August 30, 2006. http://gov.ca.gov/index.php?/press-release/3722/. Pew Center on Climate Change, "Latest News" from the states http://www.pewclimate.org/what_s_being_done/in_the_states/news.cfm

creates an economy-wide cap on greenhouse gas emissions and includes penalties for non-compliance. The cap limits California's greenhouse gas emissions at 1990 levels by 2020. This is the first state to adopt a mandatory economy-wide greenhouse gas emissions limit. California has also adopted a law, SB 1368, directing the California Energy Commission to set a greenhouse gas performance standard for electricity procured by local publicly owned utilities, whether it is generated within state borders or imported from plants in other states. The standard is to be adopted by June 30, 2007 and will apply to all new long-term electricity contracts. California is also exploring coordination of its statewide greenhouse gas reduction program with the Northeast's Regional Greenhouse Gas Initiative.

Similarly, in September 2006, the Governor of Arizona issued an Executive Order (2006-13) establishing a statewide goal to reduce Arizona's greenhouse gas emissions to 2000 levels by 2020, and 50% below this level by 2040.[54]

Other states have indirect policies that will impact future emissions of greenhouse gases. These indirect policies include the requirements by various states to either consider future carbon dioxide regulation or use specific "adders" for carbon dioxide in resource planning. They also include policies and incentives to increase energy efficiency and renewable energy use, such as renewable portfolio standards. Some of these requirements are at the direction of state public utilities commissions, others are statutory requirements.

But states are not just acting individually; there are a number of examples of innovative regional policy initiatives that range from agreeing to coordinate information (e.g., Southwest governors and Midwestern legislators) to development of a regional cap and trade program through the Regional

54 Governor Napolitano Press release, September 8, 2006. http://azgovernor.gov/dms/upload/NR_090806_CCAG.pdf

Pew Center on Climate Change, "Latest News" from the states http://www.pewclimate.org/whats_being_done/in_the_states/news.cfm

Greenhouse Gas Initiative in the Northeast ("RGGI"). The objective of the RGGI is the stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.[55]

In an effort that could provide an important foundation for implementation of a national cap on greenhouse gases, representatives of 30 states have begun discussions of a multi-state climate action registry. This effort builds on existing registries in the Northeast and California. The group is discussing development of common accounting practices and development of an internet-based monitoring system for voluntary and mandatory greenhouse gas reporting.[56]

Q. Have any states adopted direct policies that require specific emissions reductions from electric sources?

A. Yes. The states of Massachusetts, New Hampshire, Oregon and California have adopted policies requiring greenhouse gas emission reductions from power plants.[57]

Q. Do any states require that utilities or default service suppliers evaluate costs or risks associated with greenhouse gas emissions in long-range planning or resource procurement?

A. Yes. As shown in Table 2 below, several states require companies to account for the emission of greenhouse gases in resource planning.

Table 2. Requirements for Consideration of Greenhouse Gas Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in	CA	PUC requires that regulated utility	April 1, 2005	CPUC Decision 05-04-024

55 Table 5.5, at page 21 of Exhibit DAS-4.

56 O'Donnel, Arthur; "Thirty states discuss proposed emissions registry," Greenwire, October 4, 2006.

57 Exhibit DAS-4, Table 5.3 on page 18.

resource planning		IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.		
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in resource planning	MT	IRP statute includes an "Environmental Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	August 17, 2004	Written Comments Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787

VI.C. THE USE OF CARBON DIOXIDE COSTS IN UTILITY PLANNING

Q. What carbon dioxide values are being used by utilities in electric resource planning?

A. Table 3 below presents the carbon dioxide costs, in $/ton CO_2, that are presently being used in the industry for both resource planning and modeling of carbon regulation policies.

Table 3. Carbon Dioxide Costs Used by Utilities

Company	CO2 emissions trading assumptions for various years ($2005)
PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel Energy-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2003, pages 45-46; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo,. Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

Q. How should utilities plan for and mitigate the risk of greenhouse gas regulation?

A. The key part of that question is "plan for the risk of greenhouse gas regulation." Mitigating risk begins with the resource planning process and the decision as to the demand-side and supply-side options that should be pursued. A utility that chooses to go forward with a new, carbon intensive energy resource without proper consideration of carbon regulation is imprudent. To give an analogy it would be like choosing to build a gas-fired power plant without consideration of the cost of gas because one believes that building the plant is "worth it" regardless of what gas might cost.

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Company	CO2 emissions trading assumptions for various years ($2005)
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A utility that desires to be prudent about the risk of carbon regulation would, at a minimum, consider carbon regulation by developing an expected carbon price forecast as well as reasonable sensitivities around that case.

Q. Has Synapse developed a carbon price forecast that would assist the Commission in evaluating the Big Stone II Project?

A. Yes. Our forecast is described in more detail in Exhibit DAS-4, starting on page 41 of 63.

During the decade from 2010 to 2020, we anticipate that a reasonable range of carbon emissions prices will reflect the effects of increasing public concern over climate change (this public concern is likely to support increasingly stringent emission reduction requirements) and the reluctance of policymakers to take steps that would increase the cost of compliance (this reluctance could lead to increased emphasis on energy efficiency, modest emission reduction targets, or increased use of offsets). We expect that the widest uncertainty in our forecasts will begin at the end of this decade, that is, from $10 to $40 per ton of CO_2 in 2020, depending on the relative strength of these factors.

After 2020, we expect the price of carbon emissions allowances to trend upward toward a marginal mitigation cost. This number will depend on currently uncertain factors such as technological innovation and the stringency of carbon caps, but it is likely that, by this time, the least expensive mitigation options (such as simple energy efficiency and fuel switching) will have been exhausted. Our projection for greenhouse gas emissions costs at the end of this decade ranges from $20 to $50 per ton of CO_2 emissions.

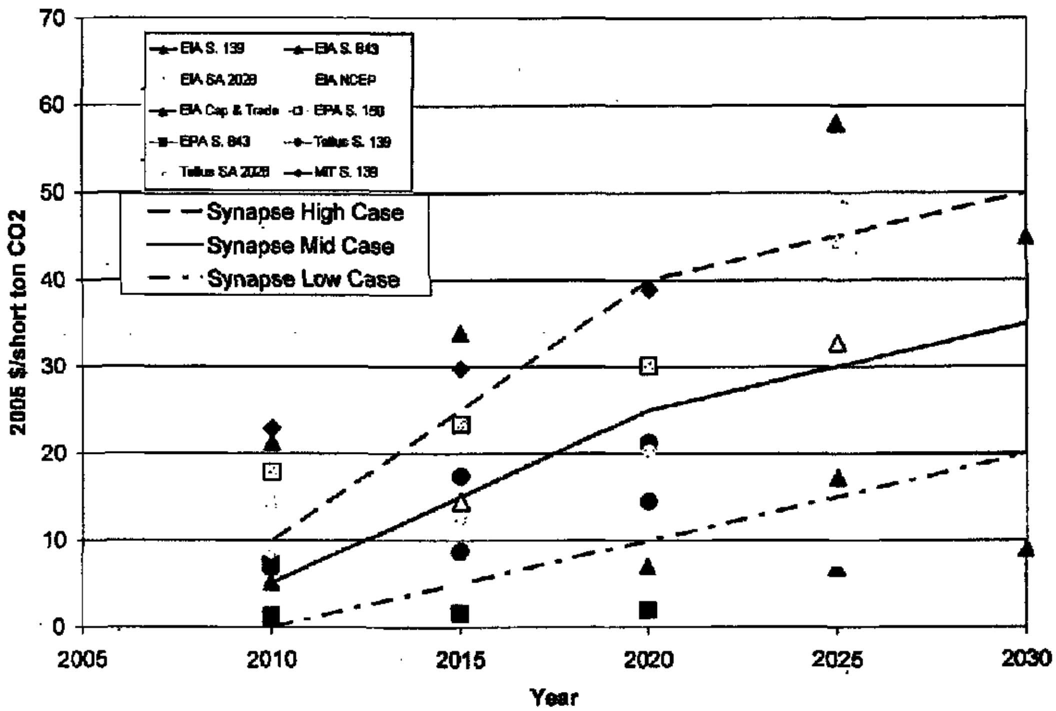
We currently believe that the most likely scenario is that as policymakers commit to taking serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complementary energy policies that lead to lower cost scenarios, and that technology innovation will reduce the price of low-carbon technologies, making the most likely scenario (the mid case) closer to (though not equal to) low our carbon cost scenario than our high carbon cost scenario.

After 2030, and possibly even earlier, the uncertainty surrounding a forecast of carbon emission prices will increase due to the interplay of factors such as the level of carbon constraints required and technological innovation. Scientists anticipate that very significant emission reductions will be necessary, in the range of 80 percent below 1990 emission levels, to achieve stabilization targets that will keep global temperature increases to a somewhat manageable level. As such, we believe there is a substantial likelihood that response to climate change impacts will require much more aggressive emission reductions than those contained in U.S. policy proposals, and in the Kyoto Protocol, to date. If the severity and certainty of climate change are such that emissions levels 70-80% below current rates are mandated, this could result in very high marginal emissions reduction costs, though we have not yet quantified the cost of such deeper cuts on a per ton basis.

Q. What is Synapse's forecast of CO_2 emissions prices?

A. Synapse's forecast of future carbon dioxide emissions prices are presented in Figure 2 below. This figure superimposes Synapse's forecast on the results of other cost analyses of proposed federal policies.

Figure 2. Synapse Carbon Dioxide Prices



Q. What is Synapse's levelized carbon price forecast?

A. Synapse's forecast, levelized[58] over 20 years, 2011 – 2030, is provided in Table 4 below.

Table 4: Synapse's Levelized Carbon Price Forecast (2005$/ton)

Low Case	Mid Case	High Case
$8.23	$19.83	$31.43

Q. Are the Synapse CO_2 price forecasts based on any independent modeling?

A. Yes. We did not perform any new modeling to develop our CO_2 price forecasts. However, as shown in Table 5 below, these 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")

Table 5: Analyses of Greenhouse Gas Regulation Proposals Considered in Synapse CO_2 Price Forecast

Policy proposal	Analysis
McCain Lieberman – S. 139	EIA 2003, MIT 2003, Tellus 2003
McCain Lieberman – SA 2028	EIA 2004, MIT 2003, Tellus 2004
Greenhouse Gas Intensity Targets	EIA 2005, EIA 2006
Jeffords – S. 150	EPA 2005
Carper 4-P – S. 843	EIA 2003, EPA 2005

Q. Please comment on the fact that several of the analyses from which you developed your CO_2 price forecast were prepared in 2003 and 2004.

A. We believe it is important for the Commission 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 presented in Table 5 above were the most recent analyses available when we developed our CO_2 price forecasts back in about the spring of 2006. However, the results of these analyses remains relevant today even though some of the studies on which our forecast were based are now several years old.

Most importantly, as can been seen from Figure 1 earlier in this testimony, almost all of the new greenhouse gas regulation bills that have been introduced in Congress are significantly more stringent than the bills that were being considered prior to the spring of 2006. As I will discuss below, the increased stringency of current bills can be expected to lead to higher CO_2 emission allowance prices.

58 A value that is "levelized" is the present value of the total cost converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

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. Do the triangles, squares, circles and diamond shapes in Figure 2 above reflect the results of all of the scenarios examined in the MIT, EIA, EPA and Tellus analyses listed in Table 5?

A. As a general rule, we focused our attention on the modeler's primary scenario or presented high and low scenarios to bracket the range of results.

For example, the blue triangles in Figure 2 represent the results from EIA's modeling of the 2003 McCain Lieberman bill, S. 139. We used the results from EIA's primary case which reflected the bill's provisions that allowed: (a) allowance banking; (b) use of up to 15 percent offsets in Phase 1 (2010-2015) and up to 10 percent offsets in Phase II (2016 and later years). The S.139 case also assumed commercial availability of advanced nuclear plants and of geological carbon sequestration technologies in the electric power industry.

Similarly, the blue diamonds in Figure 2 represent the results from MIT's modeling of the same 2003 McCain Lieberman bill, S.139. MIT examined 14 scenarios which examined the impact of factors such as the tightening of the cap in Phase II, allowance banking, availability of outside credits, and assumptions about GDP and emissions growth. We have included the results from Scenario 7 which included allowance banking and zero-cost credits, which effectively relaxed the cap by 15% and 10% in Phase I and Phase II, respectively. We selected this scenario as the closest to the S.139 legislative proposal since it assumed that the cap was tightened in a second phase, as in Senate Bill 139.

At the same time, some of the studies only included a single scenario representing the specific features of the legislative proposal being analyzed. For example, SA 2028, the Amended McCain Lieberman bill set the emissions cap at constant 2000 levels and allowed for 15 percent of the carbon emission reductions to be met through offsets from non-covered sectors, carbon sequestration and qualified international sources. EIA presented one scenario in its table for this policy. The results from this scenario are presented in the green triangles in Figure 2.

Q. Did Synapse selectively use certain scenarios from the analyses by MIT, EIA, EPA and Tellus in order to present the highest possible CO_2 prices, thereby ignoring other lower cost scenarios?

A. No.

Q. Do you believe that technological improvements and policy options will reduce the cost of CO_2 emissions?

A. Yes. Exhibit DAS-4 identifies a number of factors that will affect projected allowance prices. These factors include: the base case emissions forecast; whether there are complimentary policies such as aggressive investments in energy efficiency and renewable energy independent of the emissions allowance market; the policy implementation timeline; the reduction targets in a proposal; program flexibility involving the inclusion of offsets (perhaps international) and allowance banking; technological progress; and emissions co-benefits.[59] In particular, we anticipate that technological innovation will temper allowance prices in the out years of our forecast.

Q. Have you seen any recent forecasts of future CO_2 emissions prices that are similar to the Synapse forecast?

A. Yes. A report of an interdisciplinary study at the Massachusetts Institute of Technology on *The Future of Coal* was issued in early March 2007. Figure 3 below shows that the CO_2 price forecasts in this study are very close to the high and low Synapse forecasts.

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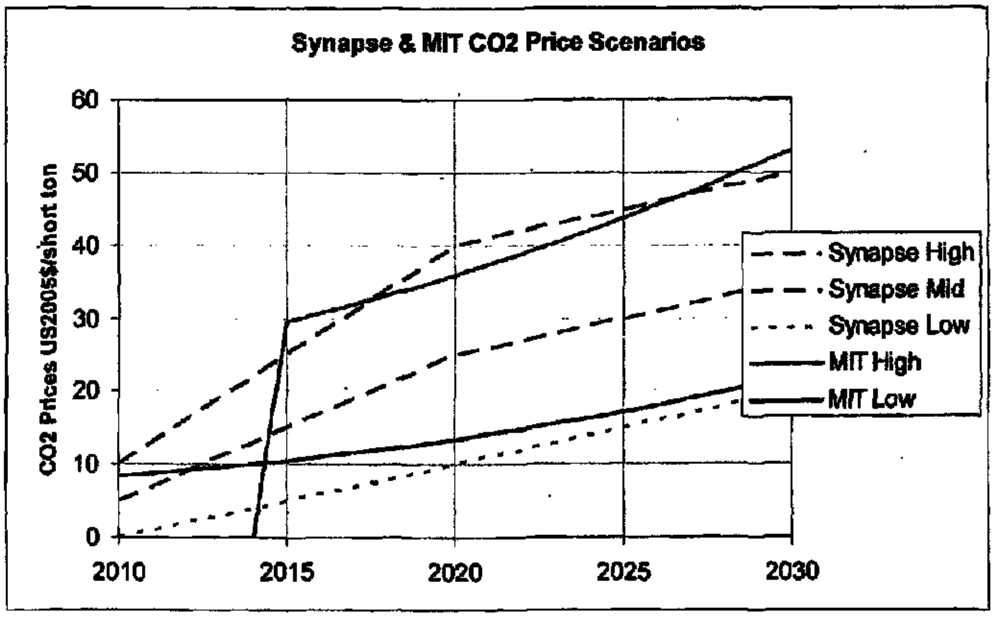
59 Exhibit DAS-4, at pages 46 to 49 of 63.

Figure 3: CO_2 Price Scenarios – Synapse & MIT March 2007 Future of Coal Study



Q. Do the Synapse carbon price forecasts presented in Figures 2 and 3 reflect the emission reduction targets in the bills that have been introduced in the current Congress?

A. No. We developed our price forecasts late last spring based on the bills that had been introduced in Congress through that time. The bills that have been introduced in the current US Congress generally would mandate much more substantial emissions reductions than the bills that we considered when we developed our carbon price forecasts. Consequently, we believe that our forecasts are conservative.

Q. Have you seen any analyses of the CO_2 prices that would be required to achieve the much deeper reductions in CO_2 emissions that would be required under the bills currently under consideration in Congress?

A. Yes. 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 Congress.

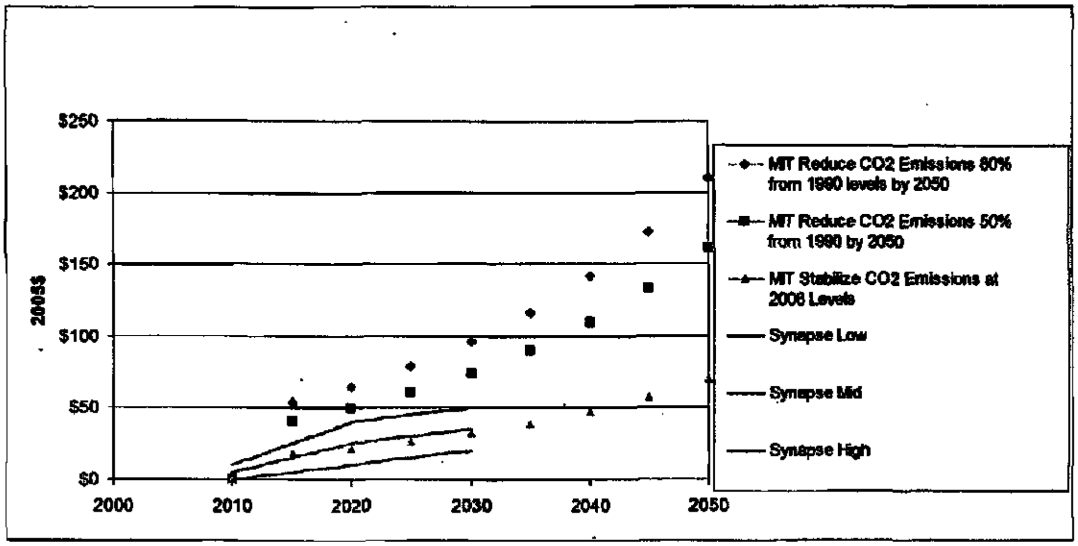
Twenty nine scenarios were modeled in the *Assessment*. These scenarios reflected differences in such factors as emission reduction targets (that is, reduce CO_2 emissions 80% from 1990 levels by 2050, reduce CO_2 emissions 50% from 1990 levels by 2050, or stabilize CO_2 emissions at 2008 levels), whether banking of allowances was allowed, whether there would be international trading of allowances, whether only developed countries or the United States pursue mitigation, whether there would be safety valve prices adopted as part of greenhouse gas regulations, etc.[60]

In general, the ranges of the projected CO_2 prices in these scenarios were significantly higher than the range of CO_2 prices in the Synapse forecast. For example, twelve of the 29 scenarios modeled by MIT projected higher CO2 prices in 2020 than the high Synapse forecast. Fourteen of the 29 scenarios projected higher CO2 prices in 2030 than the high Synapse forecast.

Figure 4 below compares the three Core Scenarios in the MIT *Assessment* with the Synapse CO2 price forecast.

[60] The scenarios examined in the MIT *Assessment of U.S. Cap-and-Trade Proposals* are listed in Exhibit DAS-4.

Figure 4: CO_2 Price Scenarios – Synapse and Core Scenarios in April 2007 MIT *Assessment of U.S. Cap-and-Trade Proposals*



Q. Did the recent MIT *Assessment of U.S. Cap-and-Trade Proposals* examine any scenarios in which there would be "safety valve" prices similar to those in the draft bill by Senator Bingaman?

A. Yes. Although these scenarios forecast significantly lower CO_2 emissions allowance prices than the Synapse mid and high forecasts, the CO_2 emission reductions achieved by 2050 in these scenarios were not close to the 60% to 80% levels that are set forth as the goals in most of the legislation that has been introduced in the current Congress.

Q. Are you recommending that the North Dakota Public Service Commission adopt these significantly higher projected CO_2 allowance prices in its evaluation of the prudence of Montana-Dakota and OTP's proposed participation in the Big Stone II Project?

A. Not at this time. However, the results of the recent MIT *Assessment* confirm the reasonableness of the range of the current Synapse forecast of future CO_2 prices.

Q. Have OTP and Montana-Dakota adequately considered the risk of greenhouse gas regulation?

A. No. The approach of the Big Stone II Co-owners is what might be called keeping their heads in the sand and hoping that the problem of global warming goes away. For example, the Co-owners could not answer basic questions about the United Nations Framework Convention on Climate Change. Request for Admission No. 22 in the Joint Intervenors' First Set of Requests for Admission in South Dakota Public Utilities Commission Case EL05-022 asked the Big Stone II Co-owners to:

> Admit that in 1992 the United Nations Framework Convention on Climate Change was adopted [IPCC 2005, p 5].

The Co-owners responded by saying that:

> Applicant has made reasonable inquiry and the information known to it is insufficient to enable Applicant to admit or deny this statement.

Similarly, Request for Admission No. 25 asked the Co-owners to:

> Admit that the most recent Assessment Report released by the IPCC is the Third Assessment Report (TAR), released in 2001, and that part of the TAR is the report of the Working Group I of the IPCC, entitled "Climate Change 2001: The Scientific Basis."

Again, the Co-owners responded, in part:

> Applicant has made reasonable inquiry and the information known to it is insufficient to enable Applicant to admit or deny this statement.

In twenty separate instances, the Co-owners could not answer requests for admission requiring them to do nothing more than admit facts that could easily be verified by an internet search (starting with the internet addresses that, in many cases, were provided in the questions) or by referring to the document(s) attached to the request.

Q. How are such responses relevant to the issue of considering carbon regulation in resource planning?

A. If a utility does not rely upon outside expertise to, at a basic level, advise the utility on future carbon regulation and second to forecast carbon allowance prices, it must rely upon its own knowledge and information gathering to do so. A major step in that process is to understand the various parties involved and what their recommendations mean to policymakers. Organizations such as the Intergovernmental Panel on Climate Change are well recognized and regarded and their thoughts on topics such as climate change do not go by the wayside. The inability to answer these basic questions, let alone put in the small effort that would be necessary to answer such questions, bodes poorly for the Co-owners' decision-making.

Q. Did OTP or Montana-Dakota reflect any potential greenhouse gas regulations in their resource planning for Big Stone II?

A. No. In some of its analyses OTP did use the Minnesota Commission's environmental externality value for carbon dioxide. However, because the Big Stone II plant would be located just across the border in South Dakota, the Minnesota Commission CO_2 externality value was $0/ton.

Our forecast of CO_2 prices assumes that the legislation controlling greenhouse gas emissions that will be implemented by the early part of the next decade will not be significantly different from the bills that have been introduced to date in Congress. While these bills may make significant strides towards lowering future CO_2 emissions, none is likely to put the country on the CO_2 emissions reductions trajectories that will be required to truly stabilize the concentrations of atmospheric CO_2. Therefore, the atmospheric concentrations of carbon dioxide will continue to increase, global temperatures will continue to rise, and the evidence of the resulting adverse climate changes from those rising temperatures will become even more pronounced. As a result, the public and legislative debates on climate change and how to deal with the threat it poses will evolve, and the American public will demand stronger governmental action to address this threat.

For these reasons, it is reasonable to expect that the stringency of carbon regulations will increase in future years in order to achieve the emissions reductions sufficient to stabilize atmospheric concentrations of CO_2. At the same time, future CO_2 prices can be expected to rise because increasing energy use will mean greater competition for a fixed or decreasing pool of emissions allowances.

Q. Have Montana-Dakota and OTP criticized your carbon price forecasts in the Big Stone II proceedings in South Dakota and/or Minnesota?

A. Yes. The Big Stone II Co-owners, including Montana-Dakota and OTP, presented rebuttal testimony before the South Dakota Commission and the Minnesota Public Utilities Commission that challenged our forecast of carbon prices.[61] However, that rebuttal testimony was not credible for several reasons.

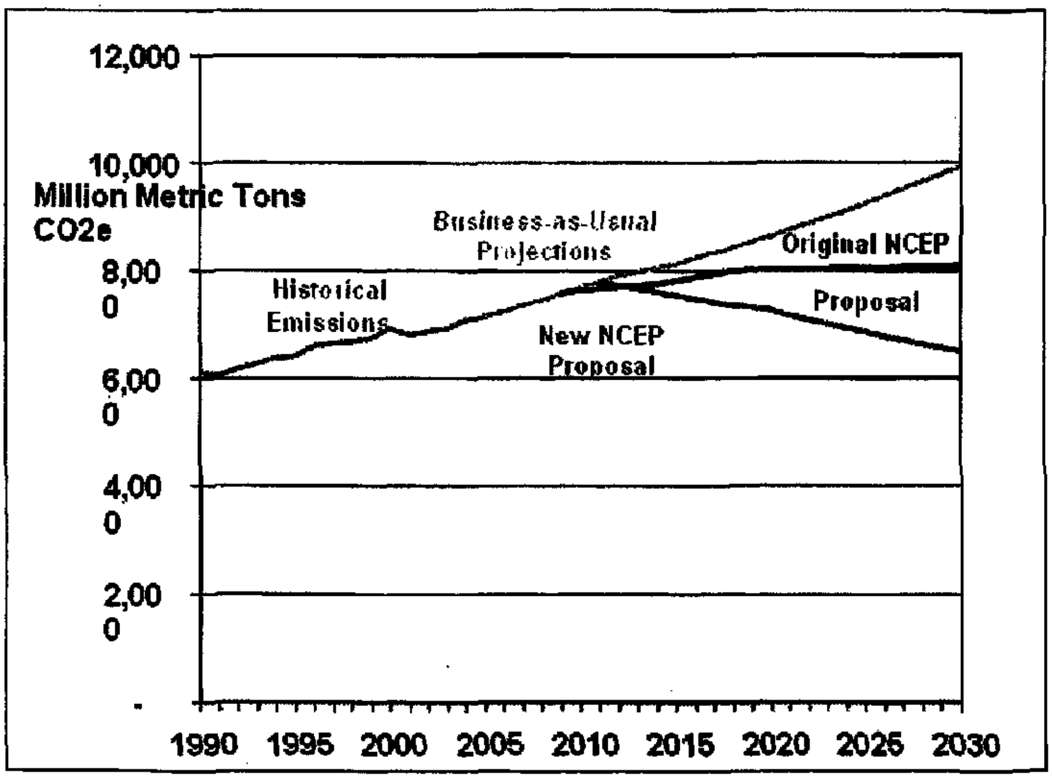
First, the rebuttal testimony on CO_2 prices that was presented by Montana-Dakota and OTP in Minnesota and South Dakota was based on a review of a single piece of proposed legislation, Senator Bingaman's Climate and Economy Insurance Act of 2005, that was discussed but never introduced in Congress. The Big Stone II Co-owners appeared to believe that this one piece of proposed legislation was the best indicator of what Congress might pass in the future and that politics and the will of the American people won't change even as the impacts of climate change become more apparent. In contrast to the Co-owners, our carbon price forecasts were based on our reviews of a number of legislative proposals that were introduced in Congress and on the results of the modeling studies of the impact of proposed legislation on future carbon prices. Our carbon price forecasts are not tied to the fate of any single bill. Rather we believe that, overall, the bills that

61 Prefiled Rebuttal Testimony of Thomas A. Hewson, Jr., Applicants' Exhibit 30 in South Dakota Public Utilities Commission Case No. EL05-022.

have been and that are being proposed in Congress are representative of the legislation that ultimately will be implemented.

Second, Senator Bingaman's draft bill was largely based on a proposal by the National Commission on Energy Policy (NCEP) from December 2004, which recommended a greenhouse gas intensity target starting in 2010 with an allowance price cap starting at $7/ton. However, the National Commission on Energy Policy recently modified its greenhouse gas regulation proposal. Instead of advocating for a reduction in greenhouse gas intensity, NCEP now proposes that starting in 2012, national emissions be reduced so that by 2020 they are at 2006 levels and by 2030, they are 15% below current levels. A graphical version of the difference between this new proposal and the proposal on which Senator Bingaman's draft bill and, consequently, the Big Stone II Co-owners' rebuttal testimony in South Dakota and Minnesota was based, is shown in Figure 5 below.

Figure 5: Original and Current NCEP Proposals[62]



Q. How much additional CO2 will Big Stone II emit into the atmosphere?

A. At its projected 88 percent capacity factor (i.e., 4856 GWH), Big Stone II will emit more than 4.7 million tons of CO2 annually.

Q. Would incorporating Synapse's carbon price forecast have a material effect on the economics of building and operating the proposed Big Stone II Project?

A. Yes. For example, the Co-owners have said that the busbar cost of Big Stone II will be $69.62/MWh (2005$) for investor-owned utilities (IOUs) and $56.38/MWh (2005$) for public power. The use of the Synapse middle CO_2 price forecast of an approximate $19/MWh increase in operating costs would represent

62 From the National Commission on Energy Policy, www.energycommission.org.

a 27% increase in cost per MWh of Big Stone II generation to the Big Stone II investor owned utilities and a 33% increase to the public power Co-owners.

Q. What would be the annual CO_2 cost to OTP and Montana-Dakota?

A. Assuming an 88% average annual capacity factor, the range of annual, levelized cost of CO_2 regulation for each Company would be:

Low Case - 4,700,000 tons * $8.23/ton * 19.3% = $7.5 million.

Mid Case - 4,700,000 tons * $19.83/ton * 19.3% = $18.0 million.

High Case - 4,700,000 tons * $31.43/ton * 19.3% = $28.5 million.

Q. Are OTP and Montana-Dakota already heavily dependent upon coal-fired generation?

A. Yes. Exhibits BM-6 and BM-7 to OTP witness Morlock's Direct Testimony shows that as of 2004, 60.3 percent (winter) to 65.3 percent (summer) of Otter Tail Power Company's generating capacity was coal-fired.[63] When oil and natural gas fired capacity is included, more than 75 percent of Otter Tail's generating capacity was fossil-fired.

Seventy-six percent of Montana-Dakota Utilities current owned generation is coal-fired.[64]

Q. Even if they add the Big Stone II Project, are OTP and Montana-Dakota pursuing resource plans that, overall, will reduce their dependence on coal-fired generation?

A. No. OTP and Montana-Dakota may be saying that they are going to be adding a diverse resource mix. However, they will remain heavily dependent on fossil-

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63 Applicants' Exhibits 10-D and 10-E in South Dakota Public Utilities Commission Case No. EL05-022.

64 Applicants' Exhibit 11 in South Dakota Public Utilities Commission Case No. EL05-022, page 8, lines 9-17/

fired generation even if they actually do pursue the resource plans that they are now discussing. In other words, participating in the Big Stone II Project will limit, not reduce, their future fuel diversity and maintain their dependence on coal.

For example, the results of Otter Tail Power's recent modeling shows that in 2007, 75 percent of the megawatt hours produced by the Company will be generated at coal-fired facilities. With the Big Stone II Project, in 2013 Otter Tail will still generate 75 percent of its megawatt hours at coal-fired plants.[65]

Q. Is this continued heavy dependence on coal-fired generation prudent?

A. No. A continued heavy dependence on coal-fired generation is not prudent. In particular, the failure by OTP and Montana-Dakota to accept that there will be significant restrictions on future greenhouse gas emissions and to reflect the potential for such restrictions in their resource planning is not prudent. We hope, therefore, that the Commission will hold that the shareholders of OTP and Montana-Dakota must bear any costs attributable to such imprudence.

VII. OTP AND MONTANA-DAKOTA'S ECONOMIC AND MODELING ANALYSES ARE BIASED IN FAVOR OF THE BIG STONE II PROJECT AND DO NOT PRUDENTLY CONSIDER THE RISKS ASSOCIATED WITH PARTICIPATING IN THE PROJECT

VII.A. OTTER TAIL POWER

Q. Have you reviewed the results of the modeling analyses that are discussed by OTP in the Testimony of Bryan Morlock and that forms the basis for OTP's participation in the Big Stone II Project?

A. Yes. As part of our reviews in South Dakota and Minnesota, we have reviewed the economic and modeling analyses which OTP has said form the basis for its continued participation in the Big Stone II Project. This includes the IRP-Manager resource planning modeling analyses that Mr. Morlock discusses.

Q. Do the results of OTP's modeling analyses provide persuasive evidence that the Company's participation in the Big Stone II Project is prudent?

A. No. The Company's evidence in support of its claim that its participation in the Big Stone II is prudent is unpersuasive for several reasons.

First, Otter Tail used the IRP-Manager model for its resource planning studies. However, OTP has acknowledged that the IRP-Manager model has significant limitations and that the company is in the process of changing to another capacity expansion model.

Second, the IRP-Manager model optimizes for lowest cost based on a defined predictable future without assessment of uncertainty or risks. Otter Tail Power did not conduct any sensitivity analyses based on variations in such critical input assumptions as the cost of Big Stone II, fuel costs, plant performance due to fuel supply disruptions, etc.

Thus, Otter Tail has not prepared any sensitivities as part of its recent modeling to evaluate the significant risks associated with building and operating a new coal-fired generating facility. For example, the company does not present any scenarios that reflect power plant power reductions or outages or increased fuel costs as a result of disruptions of the supply of Powder River Basin coal. Such disruptions have led to substantial amounts of lost plant generation and higher fuel costs at coal plants around the U.S. as a result of the train derailments and track problems experienced in 2005 on the rail lines emanating from Powder River Basin.

Otter Tail also has not prepared any sensitivity analyses to consider the economics of the Big Stone II Project assuming higher project capital costs. Consequently, it has ignored the $199 million increase in the Project's estimated costs expected to be a consequence of the Co-owners' decision in late August 2006 adopt a short-

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[65] Applicants' response to MCEA IR No. 139 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275.

term spending limitation plan that would reduce their short-term engineering and procurement expenditures.

Third, OTP's IRP-Manager analyses do not reflect any greenhouse gas regulation costs.[66] This advantages coal-fired options, such as Big Stone II, that can be expected to emit large amounts of CO_2.

Fourth, OTP assumed a January 1, 2011 commercial operation date for Big Stone II in its IRP-Manager analyses. However, as indicated in the Direct Testimony of Mark Rolfes, the plant is not scheduled to achieve an actual commercial operations date before the late spring or summer of 2012, at the earliest.[67]

Q. What limitations has Otter Tail acknowledged in the IRP-Manager model?

A. Otter Tail has identified a number of significant limitations in IRP-Manager that affect its usefulness in capacity planning. For example, the company's response to Joint Intervenors' IR No. 173 in Minnesota PUC Docket Nos. CN-05-619 and TR-05-1275 notes the following limitations:

- IRP-Manager is not Windows compatible, and has to be run at the DOS level for optimization runs. The manner in which IRP-Manager uses and manages memory is incompatible with newer PC versions. This requires that the model be operated on older PC's with slower CPU times, resulting in single optimization runs taking 5-7 days.
- IRP-Manager is limited to monitoring and calculating six emissions.
- IRP-Manager has some hard-wired limits in the software that are now becoming an issue as regulatory agencies want more options modeled and with greater complexity. Examples of some of these limits are the number of supply options, the number of interchange options, and the number of interchange options with hourly pricing.
- Data input and output capabilities from IRP-Manager are extremely limited and very labor intensive.

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66 - Applicants' response to MCEA IR No. 176 in Minnesota PUC Docket Nos. CN-05-619 and TR-05-1275.

67 Direct Testimony of Mark Rolfes, at page 13, lines 5-8.

- Error checking is extremely cumbersome. There are times when a data input error has occurred and it isn't realized until the end of a 5-7 day run, causing further delay in analysis to complete another long-term run.

Indeed, Mr. Morlock told us that, unlike some of the other Co-owners, Otter Tail had been unable to model any commercial operation date(s) for Big Stone II other than January 1, 2011. We assume that the reason for this is the extremely long time, i.e., 5-7 days, required to complete a new optimization run.

Otter Tail also has acknowledged that IRP-Manager is not well equipped to properly handle all of the federal and state incentives for wind.[68] Therefore, the company has modeled wind as being purchased from developers. However, Otter Tail is considering ownership of wind generation, which might be a more economic option than purchasing it from developers. This limitation in IRP-Manager might bias the analysis against wind alternatives by inflating the cost above what it would be if the wind resources were developed by the company instead of developers.

In addition, due to the limitations in the number of hourly priced transactions allowed within IRP-Manager, Otter Tail was unable to optimize the size of the approximately 50 MW of Manitoba Hydro purchase included in its preferred plan.[69] As result, the company intends to make that determination in its next resource plan filing, using the capabilities of its new planning model, Strategist.[70]

In summary, all of the limitations in the IRP-Manager model render it inadequate for use in determining whether the Big Stone II 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, Otter Tail Power appears to be the only utility in the nation that uses this outdated planning model

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68 Otter Tail Power Company's October 25, 2006, Supplemental Information Filing in Minnesota PUC Docket No. E017/RO-05-968, at page 4.

69 Ibid, at page 9.

70 Ibid, at page 18.

and it is even in the process of changing to a new planning model.[71] The North Dakota Commission should not rely on the results from the IRP-Manager model to find that OTP's participation in the Big Stone II Project is prudent.

Q. Mr. Morlock has noted that under Minnesota law, OTP developed a number of resource plans to satisfy regulatory requirements. Have you examined the economics of any non-Big Stone II plans developed by Otter Tail?

A. Yes. The Minnesota Commission required the Big Stone II Co-owners to present an analysis that examined the relative economics of their best plans without Big Stone II. The information that Otter Tail Power developed for use in this analysis compared the company's preferred resource plan with Big Stone II against a plan that includes a 115 MW hydro purchase in place of Big Stone II.

Q. Was Otter Tail's plan without the Big Stone II Project a least cost plan?

A. No. Otter Tail Power has said that its alternate plan was not a least cost plan because the company did not have time to execute its IRP-Manager model in full optimized fashion. Instead, Otter Tail simply substituted what appeared to be the next lowest cost resource from the preferred plan for Big Stone II in the alternate plan.[72] This means that there might have been an optimized alternate plan that has an even lower-cost than the alternate plan examined by Otter Tail.

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71 Applicants' response to MCEA IR No. 173 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275.

72 Some, but not all, of the workpapers for Otter Tail's analysis of the alternative plan to Big Stone II Project were provided as the workpapers for the analysis presented in Applicants' Exhibit 48-A by Applicants' witness Harris in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275, at Bates Page Number JCO0008272.

Q. Did the alternate plan examined by Otter Tail include more wind than the plan with Big Stone II?

A. No. Both plans were capped at 160 MW of wind.[73]

Q. Did the alternate plan examined by Otter Tail include more DSM than the plan with Big Stone II?

A. No. Both plans included the same amount of DSM.

Consequently, it is quite possible that there is a least cost plan with more wind and more DSM that has a lower overall present worth revenue requirement than the alternate plan examined by Otter Tail Power. Such a plan could reflect more DSM and more wind.

Q. Did this comparative analysis show that Big Stone II is a lower cost option than the hydro purchase reflected in the alternate plan?

A. No. As shown in Table 6 below, the difference in the present worth revenue requirements between the company's preferred resource plan with Big Stone II and the non-optimized no-Big Stone II alternate plan through the year 2020 is only $12.02 million (in 2011$) or about 0.2 of one percent of the present worth revenue requirement of the preferred resource plan with Big Stone II. Therefore, the plans have essentially the same cost during the period 2006-2020.

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73 Updated Resource Breakdown, included in the materials provided as part of the workpapers of Kiah Harris for Applicants' Exhibit 48 in Minnesota Public Utilities Commission Dockets Nos. CN-05-619 and TR-05-1275.

Table 6: Otter Tail Power Revenue Requirements

Otter Tail Power IRP Revenue Requirements
Prepared for BSPII CON Filing
October 5, 2006

OTP Discount Rate 9.80%

Units are Millions of 2011 Dollars

		Preferred Resource Plan		No BSPII Alternate Plan		Differences Between Two Plans		
	Year	Annual Revenue Requirement	PW of Annual Revenue Requirement	Annual Revenue Requirement	PW of Annual Revenue Requirement	Annual Revenue Requirement	PW of Annual Revenue Requirement	CUM PW of Annual Rev Req
1	2003	$236.71	$500.08	$236.71	$500.08	$0.00	$0.00	$0.00
2	2004	$240.66	$463.04	$240.66	$463.04	$0.00	$0.00	$0.00
3	2005	$255.65	$447.98	$255.66	[illegible]	$0.00	$0.00	$0.00
4	2006	$269.41	$429.96	[illegible]	$429.88	-$0.05	-$0.08	-$0.08
5	2007	$280.30	$407.41	[illegible]	$407.48	$0.05	$0.07	-$0.01
6	2008	$296.14	$382.02	$297.81	$384.23	$1.67	$2.21	$2.20
7	2009	$299.12	$360.62	$304.44	$367.03	$5.32	$6.41	$8.62
8	2010	$300.77	$330.25	$310.28	$340.69	$9.51	$10.44	$19.06
9	2011	$355.05	$355.05	$348.69	$348.69	-$6.36	-$6.36	$12.70
10	2012	$362.53	$330.17	$355.65	$323.91	-$6.88	-$6.27	$6.43
11	2013	$368.11	$305.33	$362.12	$300.36	-$5.99	-$4.97	$1.46
12	2014	$374.22	$282.70	$369.60	$279.21	-$4.62	-$3.49	-$2.03
13	2015	$378.22	$260.22	$376.66	$259.14	-$1.56	-$1.07	-$3.10
14	2016	$377.02	$236.24	$378.29	$237.04	$1.27	$0.80	-$2.30
15	2017	$370.78	$211.59	$375.18	$214.10	$4.40	$2.51	$0.21
16	2018	$462.35	$240.30	$468.68	$243.59	$6.33	$3.29	$3.50
17	2019	$469.78	$222.37	$477.76	$226.14	$7.97	$3.77	$7.27
18	2020	$482.33	$207.83	$493.34	$212.68	$11.01	$4.75	$12.02
		$6,179.16	$5,983.25	$6,201.22	$5,995.27	$22.07	$12.02	

Q. Have you changed any of the assumptions underlying the Otter Tail Company figures presented in Table 6 above?

A. No. The annual revenue requirement figures for each plan shown in Table 6 above were taken directly from Otter Tail Power's workpapers. All we have done is to change the PW of Annual Revenue Requirements figures to 2011$ and to add the last three columns on the right hand side of Table 6 to show the differences between the two plans.

Q. What are the relative present worth revenue requirements of the two plans when the Commission's emissions externality values are included?

A. Using the Minnesota Commission's externality values has only a very minor effect, changing the relative difference in the present worth revenue requirements between the two plans to make the non-BSII Alternate Plan approximately 0.3 of a percent more expensive. This is essentially due to the fact that the CO_2

emissions from Big Stone II have an externality value of $0/ton because the plant would be located just across the border into South Dakota.

However, if you apply the Commission's high externality values to all of the CO_2 emissions, not just those in Minnesota, the no-Big Stone II Alternate Plan is less expensive than the plan with Big Stone II by about $12 million (in 2011$) or about 0.2 percent.

Q. What are the relative present worth revenue requirements of the two plans when greenhouse gas regulation costs are included?

A. As shown in Table 7 below, the non-Big Stone II Alternate Plan becomes the lower cost option if you apply any of the Synapse CO_2 price forecasts that I have presented in Figure 2 and Table 4 above.

Table 7: Benefits and (Costs) of Otter Tail's Preferred Resource Plan with Minnesota Commission Externalities and Synapse CO_2 Prices

Scenario	Benefit/(Cost) of Otter Tail's Preferred Resource Plan with BSII compared to Alternate Plan with No BSII
Synapse Low CO_2 Prices – Low MN Externality Values	($17 million)
Synapse Low CO_2 Prices – High MN Externality Values	($19 million)
Synapse Mid CO_2 Prices – Low MN Externality Values	($80 million)
Synapse Mid CO_2 Prices – High MN Externality Values	($80 million)
Synapse High CO_2 Prices – Low MN Externality Values	($141 million)
Synapse High CO_2 Prices – High MN Externality Values	($142 million)

Consequently, Big Stone II is more expensive than the non-optimized Alternate Plan examined by Otter Tail Power if you accept all of the company's assumptions except that you either apply the Minnesota Commission's high externality values to all of the project's estimated CO_2 emissions or use any of the

Synapse CO_2 price forecasts. Moreover, these results suggest that it also is reasonable to expect that an optimized least cost no-BSII Alternate Plan that included more wind and more DSM would be even more economic than the non-optimized plan presented by Otter Tail Power as its "next best" alternative to the Big Stone II Project.

VII.B. MONTANA-DAKOTA

Q. Have you reviewed the Montana-Dakota resource planning analyses discussed by Company witness Stomberg and that form the basis for the Company's decision to participate in the Big Stone II Project?

A. Yes.

Q. Prior to the preparation of the modeling analyses discussed by Montana-Dakota witness Heidell, had Montana-Dakota prepared any economic analyses that showed the Big Stone II was the lowest cost option for its ratepayers?

A. No. Montana-Dakota's 2003 Integrated Resource Plan selected 120 MW of new combustion turbines and some improvements to existing CTs to meet the company's demand through 2021.[74] However, in its 2005 Integrated Resource Plan, where it does not appear to use any model or to perform any quantitative analysis, the company concludes that "subsequent to the filing of the 2004 IRP, Montana-Dakota determined that the plan's heavy reliance on gas-fired generation exposed our customers to considerable price and reliability risk associated with fuel cost and availability. The company believes that coal-fired generation, which has lower and less volatile fuel prices and a more stable fuel supply than natural gas, provides a better value for our customers."[75]

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[74] Montana-Dakota Utilities 2003 Integrated Resource Plan, at page iv.

[75] Montana-Dakota Utilities 2003 Integrated Resource Plan, at page 4-2.

Indeed, Montana-Dakota apparently did not prepare any economic analyses when considering whether to participate in Big Stone II. Instead, it qualitatively evaluated four options, three of which were coal-fired with the fourth being reliance on purchased power.[76] As Montana-Dakota explained in the South Dakota Public Utilities Commission Case:

- The reference [in the testimony of MDU witness Stomberg] to a "model" was generic, and was intended to convey the concept of a hypothetical, purely quantitative model.[77]
- Montana-Dakota did not perform a purely quantitative model. The statement refers to the fact the expert judgment is required in resource planning; not just quantitative modeling.[78]
- For its 2005 IRP, Montana-Dakota did not use a computer model to compare supply-side and demand-side resources.[79]

We agree with Montana-Dakota that expert judgment is required in resource planning but that is **in addition to** quantitative modeling. Thus, we find that the Company's decision to commit to a more than One Billion Dollar coal-plant without having examined the economics of the various supply-side (let alone both supply- and demand-side) options to have been imprudent.

Q. What is the expected impact of Big Stone II on Montana-Dakota's residential customer rates?

A. Montana-Dakota has estimated that the addition of Big Stone II will increase its residential customer rates by approximately 20 percent, or about 1.9 cents/kWh[80] excluding the potential impact of greenhouse gas regulation.

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[76] Response to Interrogatory 27 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents in South Dakota Public Utilities Commission Case No.EL05-022.

[77] Interrogatory 28 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents in South Dakota Public Utilities Commission Case No.EL05-022.

[78] Ibid.

[79] Response to Interrogatory 58 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents in South Dakota Public Utilities Commission Case No.EL05-022.

Q. Have you reviewed the modeling by PA Consulting that is presented in the testimony of Montana-Dakota witness Heidell?

A. Yes.

Q. Does this modeling show that MDU's participation in the Big Stone II Project is prudent?

A. No. The modeling analyses presented by Mr. Heidell are flawed.

Q. Please describe the flaws you have identified in the modeling presented by MDU.

A. Among the first things we noticed was how marginal Big Stone Unit II was, even under MDU's base case assumptions. In fact, as shown in Table 8 below, MDU's own modeling projects that the Big Stone II Project would operate at capacity factors of only 38 percent to 56 percent. These are significantly below what the other Co-owners are forecasting for the plant.

Table 8: Big Stone Unit II Capacity Factor in MDU Modeling[81]

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
53	54	55	55	55	44	44	44	45	46	56	42	39	38

However, Montana-Dakota's modeling did not assume that the company would make off-system sales. Consequently, the additional energy that MDU would receive from Big Stone II, that is, the difference between Big Stone Unit II's projected 88 percent annual capacity factor and the figures shown in Table 4 would presumably be used to make off-system sales.

Q. Does Montana-Dakota have a financial incentive to make off-system sales?

A. Yes. Hoa Nguyen of MDU testified in the Big Stone II siting permit proceeding before the South Dakota Public Utilities Commission that in North Dakota, where

80 Response to MCEA Information Request 44 in MPUC Docket No. CN-05-619.

81 Applicants' Exhibit 41-B, page A-12.

60 percent of MDU's energy is sold, the Company "is allowed to keep 15 percent of the margin" of off-system, off-peak sales.[82]

Q. Have you identified any other errors in Montana-Dakota's modeling of the Big Stone II Project?

A. Lack of risk analysis was a common error among all the Big Stone II Co-owners, but PA Consulting's report explicitly acknowledges that limitation, saying:

> PA's analysis was limited to base case scenarios using a combination of existing unit costs provided by Montana-Dakota, and PA generic unit cost assumptions. Risks related to fuel prices, load deviations from the forecast, environmental regulations, MISO market design, and a range of other factors were not included in the study.[83]

In particular, MDU did not include in its modeling any costs associated with mandated restrictions on greenhouse gas emissions.

In addition, the amount of DSM available for the model to select was very limited.

Q. Did you undertake any modeling of your own to address the limitations and errors in MDU's modeling?

A. Yes. As part of our work in the Minnesota Big Stone II dockets, we reran MDU's modeling analyses using the Strategist model.

Q. Please describe the Strategist modeling you undertook in the Minnesota dockets.

A. Our goal from the beginning was to keep the MDU Strategist database intact; only making corrections to the database as a result of major errors in the modeling inputs. MDU provided its Strategist database in response to MCEA IR 138 in that

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[82] South Dakota Public Utilities Commission Case No. EL05-022, hearing transcript at page 482, lines 10-17.

[83] Exhibit JAH-2, at page 2-1.

proceeding. The response provided us with one run. In the run, the following resources were available to the model during the planning period (2006-2025):

- 1160 MW of Big Stone II (in ten 116-MW blocks),
- 157.5 MW of wind (in five 31.5-MW blocks),
- 217.5 MW of combustion turbines (in five 43.5-MW blocks),
- 1300 MW of combined cycle (in ten 130-MW blocks),
- 580 MW of lignite coal (in five 116-MW blocks),
- 580 MW of IGCC (in five 116-MW blocks),
- 17.36 MW of DSM (in one 7.36-MW block and 2 10-MW blocks, these 10-MW blocks are mutually exclusive),
- 225 MW of a baseload contract (in three 75-MW blocks), and
- 105 MW of an Xcel peaking contract for one year (in one 105-MW block).

Q. What changes did you make to MDU's modeling?

A. We wanted to test very specific scenarios to determine whether Big Stone Unit II would remain MDU's least-cost option. As such, we ran the following scenarios:

- Include the low Synapse CO_2 price and input CO_2 emission rates for MDU's alternatives.
- Include the mid Synapse CO_2 price and input CO_2 emission rates for MDU's alternatives.
- Increased wind resource availability to 315 MW.
- Increased DSM.
- Increased Big Stone II's capital cost by 10%.

In each of these scenarios, we made *no* other changes to the model.

Q. What were the results of this modeling?

A. Table 9, below, shows the amount of Big Stone II capacity included in the least cost plan as determined by Strategist, including MDU's preferred plan.

Table 9: Amount of Big Stone II Added in Least Cost Plan

Scenario	
MDU Preferred Plan	116 MW
Low CO_2 Price	0 MW
Mid CO_2 Price	0 MW
Increased Wind Availability	116 MW
Increased DSM	0 MW
Increased BSII Capital Cost 10%	0 MW

The addition of Big Stone II is highly sensitive to model assumptions and consequently, the model only chose Big Stone II Project in the increased wind availability case that we ran.

Q. What resources did the model pick as an alternative to Big Stone II?

A. It depends upon the scenario. In general additional wind and CT capacity was added instead of Big Stone II. Table 10, below, shows the MW capacity additions of new resources in each of the four plans shown above in which the model selected none of the Big Stone II Project.

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Table 10: Capacity Additions of New Resources under Five Scenarios

Scenario	Xcel Contract	CT	Wind	MDU DSM 1	MDU DSM 2	MDU DSM 3
Low CO_2 Price		174 MW	158 MW	7 MW		10 MW
Mid CO_2 Price		174 MW	158 MW			
Increased DSM	105 MW	131 MW	63 MW	n/a	n/a	n/a
Increased BSII Capital Cost 10%		174 MW	95 MW	7 MW		

Q. Can you explain why the model selected 116 MW of Big Stone II in the Increased Wind Availability scenario that you ran?

A. Yes. The model selected 116 MW of Big Stone II in that scenario because MDU had constrained the Strategist model to select either 0 MW of its share of Big Stone II or all 116 MW. That is, the model was unable to select some, but not all, of MDU's share of the project.

We subsequently reran the Increased Wind Availability scenario and allowed the Strategist model to select between 0 and ten blocks of Big Stone II (with each block 11.6 MW in size) in 2012, instead of constraining it to choose either 0 MW or 116 MW. In this case, the model selected only 23.2 MW of Big Stone II instead of the 116 MW that the model had originally selected.

More importantly, the Strategist model selected only 23.2 MW of Big Stone II under MDU's Base Case assumptions, rather than 116 MW, when the model was allowed to select up to ten 11.6 MW blocks of the Project in 2012, instead of constraining it to choose either 0 MW or 116 MW. In addition, we found that using all of MDU's Base Case assumptions, the Strategist model did create a non-Big Stone II plan that had a slightly lower net present value than did MDU's Preferred Plan with 116 MW of the Project.

Q. Would any of these least-cost plans substitute as MDU's preferred plan?

A. No. Additional analysis would be necessary to make that determination. For example, we have not performed a combination run in which both increased wind and DSM resources were made available to the model. Our intent was not to create a preferred plan but rather to test MDU's assertion that its least-cost plan includes 116 MW of Big Stone II and the sensitivity of that conclusion to the input assumptions made by MDU.

Q. Please summarize your conclusions concerning MDU's resource planning and modeling analyses?

A. MDU's resource planning and modeling analyses do not show that Big Stone II is the lowest cost or best option for its ratepayers and, consequently, do not demonstrate that the Company's participation in the Big Stone II Project is prudent.

VIII. THE TWO ECONOMIC ANALYSIS PRESENTED BY OTP AND MONTANA-DAKOTA WITNESS ROLFES DO NOT SHOW THAT PARTICIPATION IN THE BIG STONE II PROJECT IS PRUDENT

Q. Have you reviewed the two economic studies that are discussed by OTP and Montana-Dakota witness Rolfes?

A. Yes. We have reviewed in detail the two economic studies that are included as Exhibits Nos. MR-1 and MR-2.

Q. Do these studies demonstrate that the addition of Big Stone II is prudent?

A. No. The two studies presented by Mr. Rolfes do not show that OTP and Montana-Dakota's participation in the Big Stone II Project is prudent. In particular, neither study compared Big Stone II to DSM and/or renewable alternatives in a complete and unbiased manner. Consequently, their results are not credible.

Q. Did the September 2005 *Generation Alternatives Study* (Exhibit No. MR-1) evaluate the economics of DSM or a renewable alternative to Big Stone II?

A. The *Generation Alternatives Study* did not examine DSM as part of an alternative to the Big Stone II Project. However, among the six alternatives considered, the *Generation Alternatives Study* did examine a wind-gas alternative. Unfortunately, the evaluation of the wind alternative in the *Generation Alternatives Study* had two flaws which substantially biased its results in favor of the 600 MW supercritical PC alternative that was essentially Big Stone II.

Q. What were the two flaws which critically biased the economic analyses presented in the *Generation Alternatives Study* against the wind-gas alternative?

A. First, the *Generation Alternatives Study* assumed that the wind resources had no capacity value and, therefore, required a 600 MW backup natural gas-fired combined cycle facility. Second, the *Study* limited the amount of wind in the alternative to 600 MW which meant that substantially more than half of the energy provided by the alternative would be produced by the more expensive combined cycle facility. Together, these assumptions significantly increased the cost of the wind-gas alternative in the *Generation Alternatives Study*.

Q. Is the assumption that wind facilities have no capacity value, and therefore require a 100 percent backup, consistent with the assumptions made in the most recent Integrated Resource Plans filed by OTP or Montana-Dakota?

A. No. The capacity tables in Otter Tail Power's 2006-2020 Resource Plan credit wind with a capacity value of approximately 15 percent in the summer and approximately 20 percent in the winter.[84]

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84 Otter Tail Power Company's 2006-2020 Resource Plan, dated June 28, 2005, Table 4-B, at page 4-9.

Q. Was the assumption that wind facilities have no capacity value, and therefore require 100 percent backup, consistent with the testimony sponsored by the Big Stone II Co-owners in either the South Dakota or the Minnesota Big Stone II proceedings?

A. No. The testimony of Heartland witness McDowell in South Dakota noted that wind generation is accredited to be available 20 percent of the time for MAPP load and capability planning purposes.[85] Similarly, SMMPA witness Geschwind noted a 20 percent capacity value for wind when he testifies that "SMMPA would have to install approximately 5 MW of nameplate wind capacity for every 1 MW of nameplate capacity from Big Stone Unit II to arrive at the same level of MAPP-accredited capacity."[86]

Q. Please explain how limiting the amount of wind resources to 600 MW biased the *Generation Alternatives Study.*

A. Each of the alternatives considered in the *Generation Alternatives Study* were designed to provide the same amounts of capacity for reliability (600 MW) and energy (approximately 4,625 GWh). Because it assumes that the wind resources have zero capacity value, in the wind alternative examined, the *Study* added 600 MW of natural-gas fired combined cycle capacity to "back up" the 600 MW of wind it assumed would be built. By limiting the amount of wind resources to 600 MW, the Study limits the energy that would be produced by that wind capacity to 2,102 GWh (assuming a 40 percent capacity factor for wind). This means that 2,523 GWh, or more than half of the required energy, would be generated by the far more expensive natural gas-fired combined cycle facility. This increases the overall cost of the wind-gas alternative.

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85 Applicants' Exhibit 4 in South Dakota Public Utilities Commission Case No. EL05-022, at page 8, lines 7-8.

86 Applicants' Exhibit 5 in South Dakota Public Utilities Commission Case No. EL05-022, at page 10, line 22, to page 11, line 2.

Instead of assuming that only 600 MW of wind would be built, the *Generation Alternatives Study* could have assumed that the wind-gas alternative included 800 MW of wind resources. In this scenario, wind would be expected to provide 2,803 GWh of energy, or approximately 61 percent of the total required 4,625 GWh. The remaining 1,822 GWh, or 39 percent, of the required energy would be generated by the significantly more expensive natural gas-fired facility.

Or, the *Generation Alternatives Study* could have assumed that the wind-gas alternative included 1200 MW of wind resources. In this scenario, wind would be expected to provide 4,205 GWh, or approximately 91 percent, of the total required 4,625 GWh. Only 420 MWh, or less than ten percent of the total, would have to be generated at the more expensive natural gas-fired facility.

Q. Are there any circumstances under which a utility would undertake a wind project with a dedicated gas backup constrained to run when wind is not generating energy, as the Co-owners have assumed in the *Generation Alternatives Study*?

A. It is difficult to imagine that such a situation would ever occur for the Big Stone II Co-owners. First, it is illogical and contrary to customary practice to build one generating unit to "back up" a second unit. Usual practice is to back up the entire pool of generation, not just an individual unit.

Second, to have, but not to bid or operate a gas unit, could be a violation of the current MISO rules since the Co-owners could be accused of withholding capacity from the market. This example also violates the principles of economic dispatch since a unit will run when it is economic to do so, not simply in cases where it would be supplying energy not generated by a wind turbine. So, in practice, the gas "backup" would not be constrained.

Q. Did the *Generation Alternatives Study* properly calculate the Production Tax Credit for wind facilities?

A. No. The study assumed a levelized value of $12/MWh for the Production Tax Credit ("PTC") for wind facilities, which understated the value of the PTC by not counting the additional tax benefit of the PTC because it is a credit on tax liability rather than a dollar of taxable income.

For example, a 2005 study by the Energy Information Administration ("EIA") shows that the PTC is worth approximately $28/MWh levelized over a 10-year period or $21/MWh levelized over a 20-year period, assuming a 38% marginal tax rate. Another study by the National Renewable Energy Laboratory found that the PTC could be worth as much as $23/MWh levelized over a 15-year period, assuming a 40% tax rate.

Q. Did the September 2005 *Generation Alternatives Studies* reflect the currently estimated cost of the Big Stone II Project and/or any greenhouse gas regulations?

A. No.

Q. Is it possible that there are wind with hydro and/or demand-side management measures that would have lower costs than the wind-gas combinations you have looked at in your revisions to the Co-owners' *Generation Alternatives Study*?

A. Yes. There is evidence of additional, very low cost demand-side management measures available to the Co-owners.

Q. Did the *Generation Alternatives Study* examine a combination of renewable resources, other than the 600 MW wind–600 MW gas mix, to meet the projected needs of the Co-owners?

A. No. The *Generation Alternatives Study* did not examine, with the exception of gas and wind, any combinations of resources, such as a portfolio of wind, demand-side measures, and hydro, to meet the projected needs of the Co-owners.

Q. Does the second analysis discussed by Mr. Rolfes, that is, the October 2006 *Revised Analysis of Baseload Generation Alternatives*, demonstrates that OTP and Montana-Dakota's participation in the Big Stone II Project is prudent?

A. No. The *Revised Analysis of Baseload Generation Alternatives* is significantly flawed and biased in favor of the Big Stone II option.

Q. What is the basis for this conclusion?

A. The study analysis suffers from the following flaws:

- It does not examine DSM and hydro at all.
- It rejects wind as a baseload resource and considers it as only a non-firm resource.[87]
- It assumes no continuation of the wind Production Tax Credit.[88]
- It appears to use an estimated Big Stone II Project capital cost that does not reflect the additional $199 million that Black & Veatch has projected will be the result of the short-term spending reduction plan adopted by the Co-owners in August of this year.[89]

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[87] Exhibit No.MR-2, at page 3.

[88] Ibid, at page 4.

[89] Exhibit No. MR-2, Table 1, at page 3.

Q. Is it possible that there are wind with hydro and/or demand-side management measures that would have lower costs than the wind-gas combination that has presented in Exhibit No. MR-2?

A. Yes. We believe that there is evidence of additional, very low cost demand side management measures available to OTP and Montana-Dakota.

Q. Do you believe that wind can be a baseload resource?

A. Yes. Wind can be part of a portfolio of resources that can provide needed capacity and baseload energy.

Indeed, as the 2004 *Wind Integration Study – Final Report* prepared for Xcel Energy and the Minnesota Department of Commerce has noted:

> Many of the earlier concerns and issues related to the possible impacts of large wind generation facilities on the transmission grid have been shown to be exaggerated or unfounded by a growing body of research studies and empirical understanding gained from the installation and operation of over 6000 MW of wind generation in the United States.[90]

Wind power can reduce the need for other capacity and provide low cost energy. One of the Big Stone II Co-owners, GRE agrees, stating in discovery in the Minnesota Certificate of Need proceeding for the transmission line that "GRE believes that renewables and conservation could serve at least a portion of future baseload power needs."[91] In fact, when combined with other energy resources, wind can produce energy in patterns comparable to a baseload generation facility. At the same time, the effects of short term wind variability can be mitigated by building a larger number of wind turbines and by siting the wind turbines in different geographic locations.

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[90] *Wind Integration Study-Final Report*, prepared for Xcel Energy and the Minnesota Department of Commerce by EnerNex Corporation and Wind Logics, Inc., dated September 28, 2004.

[91] Response to MCEA IR No. 73 in MNPUC Docket No. CN-05-619.

Moreover, studies and actual operating experience has shown that fairly high penetrations of wind generation can be integrated into the electricity system (up to 20% of system peak demand[92] or more) without having adverse impacts on the reliability or stability of the electric grid. Some additional regulation or load-following support may be needed if large amounts of wind are added to the grid, but that can be provided by existing facilities.[93] OTP and Montana-Dakota witness Mark Rolfes has admitted the same, saying "The [Balancing Area Authority] simply must have enough generation available to handle variations between expected and actual generating level of wind on a second-by-second basis. Presuming some type of pre-scheduling was performed based upon wind forecasts, this amount can be a relatively small fraction of the nameplate capacity of the wind."[94]

I also would make two comments regarding the claim in the that the Big Stone II Co-owners need a fully dispatchable facility. First, the electric grid and, indeed, many of the Co-owners, already have fully dispatchable facilities. OTP and Montana-Dakota have not shown any evidence why new generation also must be fully dispatchable. Second, none of the economic and/or modeling studies that we have seen from any of the Big Stone II Co-owners, including OTP and Montana-Dakota, reflected any dispatching of the proposed Big Stone II facility in response to changes in demand or any other factor(s). Instead, these studies have assumed that Big Stone II will operate "flat-out" at an 88 percent average annual capacity.

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92 "Utility Wind Integration State of the Art" report prepared by Utility Wind Integration Group in cooperation with American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association, dated May 2006.

93 "Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States," Parson, Mulligan, et al., presented at the 2006 European Wind Energy Conference.

94 Response to Interrogatory 33 of the Joint Intervenors' Sixth Set of Interrogatories and Combined Set of Request for Production of Documents.

Q. Is it reasonable to assume that the Production Tax Credit will not be renewed before it expires at the end of 2008?

A. No. We believe that it is reasonable to assume that the Production Tax Credit will be renewed given (1) its history, (2) increasing concern over U.S. dependence on foreign sources of energy, and (3) mounting concern over global warming and climate change the resulting interest in providing subsidies to non-carbon emitting technologies. This is particularly true given the results of the recent Congressional elections.

Interestingly, the Big Stone II Co-owners filed rebuttal testimony on December 8, 2006 that argued that it was not reasonable to expect that the Production Tax Credit would be extended before it expired at its then-scheduled expiration date of December 31, 2007. However, without hours of the filing of that testimony, the outgoing U.S. Congress extended the Production Tax Credit by an additional year to the end of 2008.

Q. Do the same flaws invalidate the carbon price break-even analysis in the *Revised Analysis of Baseload Generation Alternatives*?

A. Yes.

Q. Do you nevertheless have any comments on the results of the carbon-breakeven analysis in the *Revised Analysis of Baseload Generation Alternatives*?

A. The break-even carbon dioxide cost shown in the *Revised Analysis of Baseload Generation Alternatives* for the investor-owned utility ownership structure, such as OTP and MDU, without the wind Production Tax Credit is approximately \$11.10/ton. This is between our levelized Synapse low- and mid-CO_2 prices.

The break-even carbon dioxide cost shown in the study for the investor-owned utility structure, with the wind Production Tax Credit, is only approximately \$5/ton, in 2006\$. This is substantially below even our Synapse low-CO_2 price

Q. Are you surprised that the Co-owners have filed the September 2005 *Analysis of Baseload Generation Alternatives* (Exhibit No. MR-1) and the October 2006 *Revised Analysis of Baseload Generation* Alternatives (Exhibit No. MR-2) in support of their request for an advanced determination of the prudence of their participation in the Big Stone II Project?

A. Yes. The Big Stone II Co-owners, including OTP and Montana-Dakota were very adamant in their position in the hearings before the South Dakota Public Utilities Commission that such an comparison based on levelized costs was not appropriate. For example, the Co-owners noted the following in their interrogatory responses:

> It must be noted that simply comparing $/MWh busbar costs of dissimilar projects is misleading and violates the most basic principles of integrated resource planning. Such a comparison completely ignores the impact of the costs and benefits a single resource can have on other resources, and provides only limited information on how any particular resource matches up with a utility's existing resource mix, the existing load requirements, or the electrical system in total.[95]

Consequently, I am surprised that OTP and Montana-Dakota have filed Exhibits Nos. MR-1 and MR-2 if they truly do believe this way about the limits of levelized cost analyses.

For the same reason, I am similarly surprised that OTP witness Uggerud has testified that Otter Tail decided to pursue construction of a supercritical pulverized coal plant at the Big Stone site as a joint project because of "the proposed plant's low busbar cost and high reliability."[96]

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[95] Applicants' response to Interrogatory No. 17 of Joint Intervenors' Sixth Set of Interrogatories and Combined Request for Production of Documents in South Dakota Public Utilities Commission Case No. EL05-022.

[96] Direct Testimony of Ward Uggerud, at page 4, lines 12-13.

Q. Do you believe that such levelized analyses can serve a useful function?

A. Yes. Although we believe that the levelized analysis presented in Exhibits Nos. MR-1 and MR-2 are fatally flawed, as discussed above, we believe that the use of levelized costs is a useful tool in the screening of possible alternatives to be studied in greater detail to capture the various factors noted by the Co-owners.

Q. Does this complete your testimony?

A, Yes.