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BEFORE THE
MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
100 Washington Square, Suite 1700
Minneapolis, Minnesota 55401-2138

FOR THE

MINNESOTA PUBLIC UTILITIES COMMISSION
127 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Petition of Excelsior Energy Inc.
and Its Wholly-Owned Subsidiary MEP-I, LLC For Approval of Terms and Conditions For The Sale of Power From Its Innovative Energy Project Using Clean Energy Technology Under Minn. Stat. § 216B.1694 and a Determination That the Clean Energy Technology Is Or Is Likely To Be a Least-Cost Alternative Under Minn. Stat. § 216B.1693

PREPARED REBUTTAL TESTIMONY AND EXHIBITS OF EXCELSIOR ENERGY INC. AND MEP-I LLC

RONALD H. WOLK

OCTOBER 10, 2006

EXCELSIOR ENERGY, INC.

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PREPARED REBUTTAL TESTIMONY OF

RONALD H. WOLK

I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name and business address.

A My name is Ronald H. Wolk. I do business as Wolk Integrated Technical Services which is a sole proprietorship. My business address is 1056 Hyde Avenue, San Jose, CA, 95129-3026.

Q On whose behalf are you testifying?

A I am testifying on behalf of MEP-I LLC and Excelsior Energy Inc. (collectively "Excelsior"), the developers of the Mesaba Energy Project ("Mesaba" or the "Project").

Q What is your present occupation?

A I am an independent consultant specializing in energy conversion technology applied to the production of electric power.

Q Who has employed you for in this assignment?

A I am working for the consulting firm Pace Global Energy Services, LLC, which in turn, has been retained by Excelsior.

Q What is the purpose of your testimony?

A The purpose of this testimony is to comment on the testimony of Dr. Amit of the Minnesota Department of Commerce. With my testimony I intend to illustrate three things:

1. The coal plants Dr. Amit used for comparison to Mesaba, namely Big Stone II, Sherco, and Comanche, either require material adjustments in order to accurately represent their cost, after which they look very similar to the capital cost estimate included in the Fluor Enterprises, Inc (Fluor) Report, or in the cases of Comanche represents an unrealistically low cost or invalid options for comparison to Mesaba because that project is an additional unit being added to an existing plant, is scheduled to be completed in 2009, two year prior to Mesaba, and has the advantage of being executed during a period of significantly lower equipment and construction costs.
2. A comparison of the adjusted Big Stone II cost, and the cost of a new super critical pulverized coal (SCPC) plant in Fluor's report to the Mesaba Tariff terms demonstrate that IGCC, when the environmental externalities are credited, is most likely to be the least cost option.
3. The start up risk associated with the Mesaba integrated gasification combined cycle (IGCC) can be managed, and the start up of new SCPC plants with full environmental controls will experience similar challenges.

Q Please summarize your educational background and professional experience.

A I received a B.S. Ch. E. (Chemical Engineering) degree from the Polytechnic Institute of Brooklyn in 1958 and an M. S. Ch. E. from the Polytechnic Institute of Brooklyn in 1962. From 1958 to 1974, I was employed by Hydrocarbon Research Inc., located in Trenton, N.J. and was involved in the development of the commercially successful H-Oil process for converting heavy petroleum fractions into useable products by high pressure hydrogenation technology (H-Oil process) and coal into liquid fuels by the application of high pressure hydrogenation technology (H-Coal process).

In 1974, I joined the Electric Power Research Institute (EPRI), located in Palo Alto, CA, as the Program Manager for the Clean Liquid and Solid Fuels program. In that position, I was responsible for managing the Institutes' sponsored R&D programs in raw coal cleaning and upgrading, coal liquefaction by high-pressure hydrogenation, and conversion of synthesis gas (a mixture of carbon monoxide and hydrogen produced by coal gasification) into methanol. These programs involved the construction and operation of large pilot plants including 250 T/D facilities for development of the H-Coal and Exxon Donor Solvent coal liquefaction processes and a 10 T/D unit to produce methanol by the Chem Systems Once-Thru-Methanol (OTM) process. In 1980, I became Director of EPRI's Advanced Fossil Power Systems Department, which was responsible for management of sponsored R&D programs in the areas of coal gasification, gas turbines, fuel cells, fluidized bed combustion, and coal liquefaction.

I am also intimately familiar with the design, construction and operation and have multiple visits to each of the four 250-300 MW coal-fueled IGCC plants that are in operation at Wabash River (E-Gas technology), Polk County (GE, formerly Texaco technology), Buggenum, The Netherlands (Shell technology) and Puertollano, Spain (Krupp-Koppers, now combined with Shell technology).

During that period I was also involved in EPRI-supported product improvement programs with GE and Westinghouse (now owned by Siemens), related to the use of their machines in IGCC plants, specifically with issues related to the use of syngas, produced by coal gasification processes, in place of natural gas and refined petroleum products normally used as fuel for those machines.

Since 1994, I have been an independent consultant to the U.S. Department of Energy, EPRI, utility companies, industrial companies, engineering companies, and technology development companies supporting their efforts to assess, develop, and commercialize new energy conversion technologies. As part of my consulting work for EPRI, I co-authored a series of published reports on improving the performance of conventional pulverized coal-fired power plants. My resume is attached as Exhibit __ (RHW-1) to this testimony.

II. COMPARISON OF BIG STONE AND FLUOR SCPC POWER PLANT AND POWER COSTS

Q Did you review the Fluor Report *Independent Analysis of Generation Technologies for a 600 MW Coal-Fired Power Plant in Minnesota* and its Addendum *Economic Analysis of SCPC Plant*, December 2005?

A Yes

Q What is your opinion of this report

A This report, prepared by Fluor, summarizes the estimated costs of building a 600 MW state-of-the-art, Supercritical Pulverized Coal (SCPC) in Minnesota. Fluor's qualifications are, in my opinion, appropriate for this work of preparing preliminary cost estimates for proposed plants. In this report Fluor mentions that:

> [I]t is among the top three in their (Engineering News Record-clarification inserted by RHW) Top Design and Build Firms list and Top 100 Contractors by New Contracts List. In recent years Fluor has built coal-fired and natural gas-fired power plants with a total capacity of

> more than 120,000 MW. Fluor has constructed more new power plants in the United States than any other single EPC firm.

The preliminary EPC (engineering, construction, and procurement costs) information that Fluor developed provides an estimate of the cost of the power plant within the plant boundaries. Infrastructure and facilities outside those boundaries (transmission lines, water supply, rail lines, roads etc.) are not included in the EPC numbers. At this stage of development contingencies (±30%) are often applied to account for unknowns because equipment lists change as detailed specifications develop, material and labor costs change in response to market forces, and the permitting processes may lead to additional changes and cost to meet local requirements.

It is only after a very complete set of information has been collected for any set of alternatives that a precise comparison can be made. It is very important that the comparisons be done with as many of the potential cost items known and quantified. For example, utility accounting practices may lead to some of the costs of a new power generation facility not being directly allocated to specific projects. These may include preliminary scoping studies, project development costs, environmental reviews, and regulatory response expenses during the project approval process.

Q What about the cost estimate of the EPC?

A The EPC plant costs developed by Fluor for the 600 MW SCPC plant is **[TRADE SECRET BEGINS TRADE SECRET ENDS]** (3rd Quarter 2005$). With escalation of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** to bring it to 2011$, the estimate of EPC costs increase to **TRADE SECRET ENDS] TRADE SECRET ENDS]** . This is **[TRADE SECRET BEGINS**

TRADE SECRET ENDS] the updated EPC estimate of $2168 submitted on September 12, 2006 by Black and Veatch, for the 600 MW SCPC Big Stone II project.

Q And do you feel the non-EPC Costs are realistic?

A For the most part the values used for the non-EPC costs are reasonable compared with other studies reviewed for this testimony. The allowance for escalation of 2.5% is appropriate and close to the numbers used by Burns and McDonnell in the Big Stone II study. The average annual availability factor, which can have a major impact on the MWH cost, of**[TRADE SECRET BEGINS TRADE SECRET ENDS]** used by Fluor is **[TRADE SECRET BEGINS TRADE SECRET ENDS]** used for the Big Stone II plant. Fluor calculated **[TRADE SECRET BEGINS TRADE SECRET ENDS]**for the total of IDC and financing charges while the most recent B&V update for Big Stone II calculated $316/kW for those same charges.

The Plant O&M values used by Fluor and Burns and McDonnell differ significantly,. Fluor used **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for Fixed O&M and **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for Variable O&M. For an estimated capacity factor of 88%, the total estimated by Fluor for Plant O&M costs is **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Burns and McDonnell used $10.11/kW-year for Fixed O&M and $2.23/MWH for Variable O&M. For an estimated capacity factor of 88%, the total estimated by Burns and McDonnell for Plant O&M costs is $3.54/MWH. Neither of these Plant O&M estimates includes Insurance and Taxes. It should be noted that in its calculations of Total O&M, used in Figures A2 and A4 of the Addendum to the Fluor Report, Fluor included the costs of Insurance and Taxes in their estimated Total O&M costs. EPRI estimates for SCPC Plant O&M costs are in the range of $8-9/MWH. (George Booras and Neville Holt; ***Pulverized Coal and IGCC Plant Costs and Performance Estimates***; Gasification Technologies 2004, Washington, DC, October 2-6, 2004; Available at www.gasification.org).

Q Do the coal plants sited in Dr. Amit's testimony represent power plants, specifically Big Stone II, Sherco 4, and Comanche 3 that provide valid comparisons to the Fluor SCPC and the Mesaba Tariff?

A The analysis done by Dr. Amit appears to be calculated based on the information provided to him, so my comments and observations are less about Dr. Amit's calculations, and targeted to the quality, timeliness and thoroughness of the information provided to him.

Q Can you comment on the Big Stone II costs and prices, as compared to the Fluor estimate?

A In his testimony, Dr. Amit compared the Electricity Tariffs for the Mesaba IGCC plant contained in the Excelsior Energy Inc. Cost Analysis and Comparison Report, December 2005, to those of the proposed Big Stone II Supercritical Pulverized Coal (SCPC) plant. The result of his calculations was a predicted Levelized Nominal Price of electricity of $92.99/MWH for the Mesaba plant. This was compared to the estimated Levelized Nominal Cost of $59.52/MWH for electricity from the proposed Big Stone II SCPC project. In response to reports of large increases in the cost of that project, Dr. Amit calculated that the Levelized Nominal Cost of electricity would be $74.48/MWH, if the capital cost of the Big Stone project increased by 23%.

The EPC component of total capital cost for the IGCC plant was estimated by Fluor Enterprises Inc. (Fluor) at **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.In a parallel activity Fluor estimated the capital cost of a 600 MW SCPC unit, similar to Big Stone II in terms of fuel, size, environmental controls, and steam cycle conditions located near Monticello, MN. The EPC cost of the plant was estimated at **[TRADE SECRET BEGINS TRADE SECRET ENDS].**Fluor provided a further breakdown of the Total Estimated Capital Cost (***Figure A1 of Fluor Independent Analysis of Generation Technologies for a 600 MW Coal Fired Power Plant in Minnesota-Addendum Economic Analysis of SCPC Plant***) for that plant of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** which includes **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for the Estimated EPC cost, **[TRADE SECRET BEGINS TRADE SECRET ENDS]** as an Allowance for Escalation, **[TRADE SECRET BEGINS TRADE SECRET ENDS]**as an Allowance for Other Construction Costs including event-driven cost contingency and contractor's risk fee, infrastructure and off-site costs, and owner's costs and contingency, and **[TRADE SECRET BEGINS TRADE SECRET ENDS]** as an Allowance for Interest During Construction (IDC) and debt placement fees. This information is summarized in Table 1 below. Dr. Amit did not calculate a Levelized Nominal Cost of electricity/MWh, but the calculation of that is attached as Table 2 and it results, using his discount rate and methodology, in a value of $98.72/MWh.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

In his testimony (Exhibit 32) submitted on October 2 referring to the Big Stone II project, Mark Rolfes of Otter Tail Power Company testified that "the proposed power plant is estimated to cost approximately $1.366 billion (an increase of just over $300 million) in 2011 $". In his testimony (Exhibit 33H), also submitted on October 2, 2006, Kermit E. Trout, Jr. of Black and Veatch provided a breakdown of that estimated EPC cost and other costs (Exhibit 33H). The EPC costs totaled $1.342 billion ($2130/kW) with additional costs of $98 million ($156/kW) for a B&V reserve, $38 million ($60/kW) and in owner's costs, and $15 million ($24/kW) as a reserve for owner's costs. In Exhibit 40-B of that testimony updated estimates were included for Interest During Construction of $169.5 million ($269/kW) and financing costs of $42.4 million ($67/kW). The difference between the sum that I calculated of $2744/kW is slightly different than the $2691/kW noted in Exhibit 40-B. All of the above information above is summarized in Exhibit 1 below.

Table 2. Summary of Various Investments and Levelized Nominal Prices of Electricity

Plant	EPC Cost $/kW (including esc.)	Other Construction Costs, $/kW	IDC and Debt fees, $/kW	Total Cost, $/kW	Levelized Nominal $/MWH (Source)
Fluor SCPC 3rdQ 2011$	**TRADE SECRET BEGINS**			**TRADE SECRET ENDS]**	98.72 (Excelsior)
B&V Big Stone II 2011$	2168	240+ more for items not included	336	2744+ more for items not included	74.48 (Amit)
Original Burns and McDonnell Estimate 2011$	1800	Not included	Not included	1800 + more for items not included	59.52 (Amit)

Typically, EPRI cost studies show that another 25-30% is added to the EPC contract to cover IDC and other owner costs. (EPRI Report 1000316, ***Evaluation of Innovative Fossil Fuel Power Plants with CO2 Removal,*** December 2000). From the data in Table 2, I calculated that B&V added about 29% to their estimate, while Fluor added **[TRADE SECRET BEGINS TRADE SECRET ENDS]** to theirs. It is not clear from my review of his testimony that Dr. Amit calculated the Levelized Nominal Price of Electricity using values that reflected the total project capital requirement or just some of the necessary components, primarily EPC costs. What appears odd in my opinion is that the adjusted estimated EPC numbers, for both the Big Stone and Fluor SCPC projects are **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Since the original capital cost estimates for the Big Stone SCPC and the Fluor SCPC plants are only **[TRADE SECRET BEGINS TRADE SECRET ENDS]** different, with the **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, it seems inconsistent that the Levelized Nominal Cost is so markedly different, especially since the heat rates of the two plants are very close, 9369 Btu/kWh for the Big Stone II plant and **[TRADE SECRET BEGINS TRADE SECRET ENDS]** Btu/kWh for the Fluor SCPC plant. The difference in O&M cost estimates amounts to about **[TRADE SECRET BEGINS** *r* **TRADE SECRET ENDS]** for Big Stone. Part of that difference may be due to shared staffing between the Big Stone 1 and proposed Big Stone II plants. This would not be available to an initial unit plant such as proposed by Fluor.

Based on those relative costs, the costs of electricity for the two plants should be much closer to one another, rather than 25% apart, since the overall capital estimates of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and $2744/kW, which is the major element in the levelized cost of electricity calculation are only about **[TRADE SECRET BEGINS TRADE SECRET ENDS]** apart. Since both calculations used a similar IOU capital structure, the differences appear to be related to the total capital costs of the plant, specifically those costs associated with non-EPC costs and AFUDC, and the O&M costs (including all Administrative and General, O&M, and owners' costs), where Big Stone's O&M costs are **[TRADE SECRET BEGINS TRADE SECRET ENDS]** than those estimated by Fluor.

Q Can you comment on the Sherco 4 costs?

A In his testimony, Dr. Amit reports that the estimated Levelized Nominal Cost for electricity from the Sherco 4 unit would be **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. In the NSP Baseload Process Report filed with the Minnesota PUC in November 2004, NSP reported on its future power generating options. As part of that project they reviewed seven different sites in Minnesota, South Dakota and Wisconsin, including the Sherco site as potential locations for a 600 MW plant. On page 13 of that report, they stated that:

> "The costs of unescalated capital and fixed O&M estimates for each of the seven sites are very close, and all are in the range of $1.4 billion (or $1860/kW) ±5%. These estimates do not include transmission or rail spur capital costs. Fixed O&M estimates are approximately $18/kW-year, except for Sherco 4.
>
> The capital cost estimate for Sherco 4 is not substantially lower than the capital cost estimates for the other sites because very little in the way of common or shared equipment could be used from the existing generating

> units at that site. The most significant example of this is in the coal unloading and handling operation that would require an entirely new system because the existing coal unloading and handling system is already operating at maximum capacity. Fixed O&M costs for Sherco 4, however, are expected to be much lower because there would be fewer incremental staffing additions needed to support plant operations."

Q Is this a valid set of cost assumptions?

A The costs are substantially lower than those of Big Stone and those estimated by Fluor. Even if the $1860 did not include AFUDC, it would still be over 25% lower than the cost of Big Stone (at $2411), and I have already pointed out that the Big Stone number appears to include a lower level of non-EPC capital costs.

Without doing substantial pre-engineering work, it is difficult for generic estimates to accurately capture the total, timely costs for building a particular plant. The Sherco capital cost estimate does not appear to have been developed in the same level of detail as the Big Stone analysis or the Fluor estimate for a hypothetical SCPC plant.

Finally, O&M Costs of even $18/kw-year would appear on the low end, and the proposition that Sherco's costs may be even lower is not consistent with the total costs of owning and operating a unit, inclusive of all owner and Administrative and General costs (such as insurance and property tax).

Q Can you comment on the Comanche 3 costs?

A In his testimony, Dr. Amit reports that the estimated Levelized Nominal Cost for electricity from the Comanche 3 unit, now under construction and scheduled for operation in 2009 would be **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. The Comanche 3 unit in Colorado is a 750 MW SCPC unit that will be fired on PRB coal. This is a well-integrated, brownfield site and the project had the cost advantage of avoiding at least some of the rapid escalation in equipment and labor costs that has occurred recently. Even Xcel has noted that this is not a valid comparison to building a plant in the 2008-2011 timeframe, as highlighted in their response to requests to NSP for additional background information to support Dr. Amit's testimony. The Minnesota Commerce Commission response includes the following quote:

"NSP believes that the request for information is not relevant to Minnesota due to weather, altitude, and site differences between Comanche and the considered site in Minnesota (Sherco). . . . The Comanche 3 estimates do not includes costs of other associated Comanche project work at Units 1 and 2 that was necessary" for approval of Comanche 3.

Q What are your conclusions from this analysis of the SCPC options?

A The Fluor report appears to be very complete in terms of identifying all the costs that must be considered in arriving at an estimate for a new, grass roots SCPC power plant. In studies that focus on comparing different technologies, individual contractors such as Fluor, Burns and McDonnell, and Black and Veatch, each company uses its experience in the competitive market place to develop competitive bids for the defined parts of the plant. It is not surprising therefore that the EPC estimates are reasonably consistent with one another. That section of the project, namely the power plant within the plant boundaries (battery limits) is well-defined and reliable estimates can be prepared by various contractors. As noted previously, the costs of newly announced plants by AEP are consistent with the values proposed for the Fluor and Big Stone SCPC plants.

The difficulty in comparing estimates is the undefined auxiliaries to the plant which lie outside the plant boundaries such as rail lines, water supplies, roads, building requirements to deal with weather conditions, waste disposal options, by-product markets, etc. One striking example of this is in the Black and Veatch testimony is that they were able to lower the capital cost of the Big Stone II project by $165 million by changing the approach to water supply.

The typical practice of contractors is to provide rough estimates of the capital necessary to fund the cost of these auxiliaries, but it is often done without hard, site-related data available that are needed to support firm estimates. In addition contingency funds are allotted to deal with unforeseen events, more rapid escalation in equipment and labor costs, and other items. Fluor has provided a **[TRADE SECRET BEGINS TRADE SECRET ENDS]** Allowance for Other Construction Costs which include event-driven cost contingency and contractors risk fee, infrastructure and off-site costs, and owners cost and contingencies of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. The Black and Veatch update (Exhibit 40-B) provides reserves for Black and Veatch and Owners Risks of $240/kW. The definitions appear to be quite different, but there is no breakdown of this **[TRADE SECRET BEGINS TRADE SECRET ENDS]** difference. It should be noted that the difference amounts to most of the difference between the total capital cost estimate of Fluor of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for the Fluor estimate and $2744/kW for the updated Black and Veatch estimate. Since this difference should not exist for a single well-defined real project, it suggests that either Black and Veatch may not have included all the items that Fluor did or that Fluor took very conservative contingency estimates. For a real project at a specific site, the cost of a 600 MW SCPC plant should be very close to the same if built by any one of a number of well-qualified contractors. More information is needed on the details of these estimates to make sure that they are truly consistent. The cost of a 600 MW SCPC project and the cost of electricity from that project should not be significantly different if located in Minnesota or South Dakota.

The overall analysis by Fluor comparing the Mesaba and SCPC plants in Minnesota shows that when all aspects are considered there is less than a 7% gap in Levelized Nominal Power Coasts with the IGCC plant producing lower cost power.

III. EXTERNALITIES MAKE IGCC THE LEAST COST OPTION

Q When environmental externalities are included, how do the Big Stone II and Fluor SCPC costs compare to the Mesaba Tariff?

A The emissions levels from SCPC and IGCC plants are fairly well understood. Minnesota underwent an extensive study to quantify the externality costs of these emissions (NOx, SO2, CO, CO2, and PM10) several years ago. On the Commission's website these values are published in 2005$. Independently reviewing the emissions and associated externality values, the IGCC plant's cost is 0.5% lower per MWH than the SCPC plant. There is a $17 million difference in PVSC in the value of Minnesota Externalities with the advantage accruing to IGCC. These values are based on an independent report produced by ICF Consulting that estimated that the externality costs of PM 2.5 are three times higher for the SCPC plant than IGCC. Should the effects of PM 2.5 be considered, the benefit accruing to IGCC in terms of PVSC increases by an additional $137 million.(Figure 8 ***Excelsior Energy Report, Section III, Cost Analysis***

and Comparison, December 2005). Avoidance of these additional costs should be included in any cost analysis, considered as part of the socioeconomic benefit of the proposed plants, and as a hedge to consumers of likely future regulations that would require internalization of some or all of those costs.

Mercury capture is an extremely difficult process. Both the Fluor designed IGCC and SCPC plants have been designed for 90% capture of mercury. Mercury capture levels of >90% have been demonstrated at the Tennessee Eastman Coal Gasification plant in Kingsport, TN, while the Powdered Activated Carbon (PAC) technology for use in the SCPC plants has only been tested at smaller scales in pilot demonstration projects. Other mercury capture technologies are under development that may turn out to be superior to PAC. Therefore at this time there is a much higher likelihood that the IGCC plant will meet its mercury capture goals. If this occurs additional externality benefits could accrue to the benefit of the Mesaba IGCC project.

There is a difference between the inherent marketability of the solid wastes from an IGCC and a SCPC power plant. The IGCC plant collects sulfur in the form of 99+% pure solid sulfur. In a SCPC plant, sulfur can in some cases be captured in the form of gypsum ($CaSO4$) crystals. Local markets may exist for either or both of these products, but it is very site dependent. At the Polk IGCC plant in Florida, sulfuric acid is produced rather than solid sulfur because a large local market exists that utilizes the acid for fertilizer production. Some power plants with wet scrubbers are able to sell the gypsum that they make for wallboard production. Slag produced in IGCC plants is inert, which has led to its sale in some cases for use as construction backfill asphalt aggregate or landfill cover operation. Bottom ash and fly ash from SCPC is usually land-filled.

Overall, the solid waste impact of an IGCC plant should be substantially less than that of an SCPC plant, reducing costs to consumers.

Because of these considerations, I conclude that IGCC is likely to be a least cost resource.

IV. IGCC PLANT AVAILABILITY

Q Is the proposed target availability of the IGCC power plant, 60% in the first year, 70% in the second year, 80% in the third year, and 91% thereafter reasonable?

A The four 250-300 MW, single-train, coal-fueled IGCC demonstration plants that began operation in the mid 1990's, which are now operating commercially, form the core of experience with coal-fired IGCC power plants. Additional information that can be utilized in the design of improved coal-fueled IGCC plants is being generated in the large number of coal- fueled gasification plants that produce synthesis gas for chemical production world-wide, and IGCC plants fueled with coke and heavy oil provide additional information available for use in coal-fueled IGCC plant design.. The coal-fueled IGCC plants are the NUON plant located at Buggenum, The Netherlands (Shell gasification technology, Siemens Combined Cycle), TECO plant located in Polk County, FL, (GE gasification technology, GE Combined Cycle), the Wabash River plant located near Terre Haute IN (E-Gas technology, GE gas turbine), and the Elcogas plant located near Puertollano, Spain (Krupp-Koppers technology, Siemens gas turbines). The objective of these plants was to demonstrate the scale-up of each coal gasification technology including the gas clean-up and combined cycle components. As shown below in Figure A, each of these plants had start-up operational issues that had to be resolved, before satisfactory levels of availability could be obtained. There were a wide variety of problems encountered in the gasification and heat recovery sections of these plants during the first two to three years of plant operation. These were resolved through correction of design errors, the use of improved materials, and changes in equipment design. Problems were also encountered with the combined cycle portion of some plants that negatively impacted availability before solutions to combustion and mechanical problems were implemented. Those solutions have been incorporated in the gas turbines that have been used with better results in newer IGCC plants fueled with heavy oil and coke.

The proposed Mesaba plant consists of a total of three gasification trains, two operating plus one spare, so that the plant can achieve the desired level of long-term availability. The addition of the spare train markedly improves the expected availability of the Mesaba plant versus existing and proposed IGCC plants. Each of these three trains has essentially the same capacity (~250 MW) as the train that has been in operation at the Wabash River IGCC plant since 1996. That plant operates on mixtures of petroleum coke and high sulfur Midwestern coals. That experience coupled with the seven years of experience with E-Gas technology at the 160 MW Plaquemine IGCC plant on PRB coal, provides an adequate basis for designing the Mesaba plant, which will use an economically optimized mixture of PRB coal petroleum coke and Illinois 6 coal. The design of the plant has been based on the use of a maximum of 50% petroleum coke mixed with coal. The use of petroleum coke requires that additional sulfur removal capacity be included in the plant design. That added sulfur removal capacity results in an EPC cost increase of 2-3%.

I anticipate that the technology improvements that were incorporated into the Wabash River plant will be utilized in the design of the Mesaba plant and many of the early problems with availability will be reduced in scope and duration, or eliminated. Coupling technology improvements with the spare train, I believe that the projections of plant availability put forward by Excelsior Energy for the Mesaba plant are reasonable.

Additionally, the Mesaba plant is being built under an IPP model, utilizing a Turnkey EPC contract; the use of this construction method should yield substantially better startup and performance than the demonstration, non-EPC structures uses to build some of the plants mentioned above. In an EPC agreement, there are typically incentives built in to motivate the contractor to meet time, budget and performance targets.

Q Are there any technical issues associated with the performance of new SCPC plants that could affect availability and how would you expect them to compare to IGCC?

A According to the Fluor study, no supercritical pulverized coal fired plants have been built in the US since the early 1980s. While the fleet of existing units previously built totals slightly more than 100 units, only 8-10% of those units are fueled with Powder River Basin coals. None of these units fueled with Powder River Basin coal are currently equipped with the full-complement of pollution control equipment, including wet scrubbers for SOx emission control, Selective Catalytic Reduction (SCR) for NOx emission control, and Powdered Activated Carbon and Fabric Filters for mercury emission and particulate emission control, that has been specified for the SCPC plant that Fluor developed for the Monticello site. During the last twenty years, the recent evolution and development of designs of SCPC units equipped with extensive emission control systems and experience with their operation has occurred in Europe and Japan rather than in the United States. That experience will have to be translated into units that are constructed and operated in the US fueled with PRB coal. Existing pulverized coal plants fueled by PRB have experienced fouling in the boiler that has resulted in performance issues downstream.

This experience indicates a likely situation where the first and perhaps several more of the initial fleet of such new SCPC power plants fueled with PRB and equipped with extensive emission control equipment for SOx and NOx removal and still-to-be commercially demonstrated mercury capture technology, will undergo many of the same types of startup problems that were experienced in the first four single-train IGCC demonstration plants built during the late 1990s. In many cases, the negative impact on initial IGCC plant availability resulted from combining several existing technologies in new ways. Gasification technology is not new, and neither is the combined cycle plant; the combination of the two led to some technical issues that had to be overcome. This is similar to the combination of PRB coal and a super critical steam cycle, with commercially available wet scrubbers and SCR for SOx and NOx emission control respectively with, the mercury emissions control technology which is still in a demonstration stage.

Q In Dr. Amit's testimony, was there any discussion of the value of the potential for an IGCC plant in Minnesota to "contribute to a transition to hydrogen and a fuel resource" and "the potential to capture carbon", as requested by Commissioner Nickolai and noted in the Hearing transcript of July 27, 2006?

A There were no explicit values mentioned in Dr. Amit's testimony for the potential benefit of hydrogen production and CO2 capture. IGCC has an inherent advantage over any combustion technology for both hydrogen production and reduced cost of CO2 capture. Hydrogen is a product of the gasification process and not of the combustion process. Coal gasification, which is usually done with oxygen at elevated pressure, is equivalent to the partial combustion of coal, producing a high pressure mixture of hydrogen, carbon monoxide, and carbon dioxide gases as essentially the only products. Coal combustion, such as practiced in SCPC power plants at atmospheric pressure, does not produce hydrogen and completely converts the carbon in the fuel to carbon dioxide and dilutes it with about 84-88% nitrogen, which is contained in the air used to burn the carbon, in the product gas.

The carbon monoxide in the gasification product gas can then be almost completely converted by reaction with steam, (which is referred to as the shift reaction) to produce additional hydrogen and carbon dioxide. About half of the approximately 120 gasification plants now operating in the world (James and Robert Childress; ***2004 World Gasification Survey Gasification Technology***; October 4-6, 2006, Washington, DC-available at www.gasification.org) utilize the gasification and shift reactions in sequence to produce a mixture of hydrogen and CO2. The CO2 and hydrogen are then separated into separate products.

While CO2 can also be separated from the boiler flue gas, the technology that is used is much more expensive than in an IGCC plant, requiring more capital investment and greater use of energy. The published Minnesota externality value is $3.76/ton (2005$) of CO2 emitted. Since the heat rate of the IGCC and SCPC plants are within about 1% of one another, this externality value does not provide a significant differential cost benefit to IGCC if CO2 is to be emitted. However, there would be a significant advantage if CO2 must be captured prior to permanent sequestration because of the lower CO2 capture cost with IGCC than with SCPC.

Another advantage of early adoption of IGCC technology is that it, in my opinion, has a greater potential for significant technology improvement, because the gaseous product is converted to electricity at relatively high efficiency in a gas turbine today and potentially at even higher efficiency in conversion technologies under development. Projects such as the Mesaba IGCC project present Minnesota with an opportunity to move from the combustion technology curve, which has relatively little to gain in future efficiency improvements, to the gasification technology curve which offers the possibility of significant efficiency improvements.

Q Is this the end of your testimony?

A Yes.

EXHIBIT ____ (RHW-1)

Ronald L. Wolk, Principal Consultant

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Pace Global Energy Services, LLC

Industry Experience: 45+ years

Qualifications and Experience:

Mr. Wolk has over 45 years of experience in assessing, developing and commercializing advanced power generation and fuel conversion technology (1958-2006). For twelve of these years, Mr. Wolk has been an independent consultant specializing in IGCC, synthesis gas conversion, gas turbines, fuel cells, distributed generation, coal conversion, improving existing coal fired power plants (1994-2006). Prior to this work, Mr. Wolk was engaged in similar efforts as Director of EPRI's Advanced Fossil Power Systems Department (1980-1994)

Summary of Representative Projects:

Client	Description of Assignment
US DOE NETL	• Critical review of a detailed report on the economics of power production from coal and natural gas
EPRI	• Strategic planning for fossil fueled power generation R&D • Evaluation of advanced coal conversion technologies for the Coal Fleet program • Development of advanced concepts for future IGCC plants with integrated CO2 capture
Clean Coal Energy LLC	• Technical assessment and support for development of a Direct Carbon Fuel Cell technology
National Research Council	• Member of panels selected to assess a methodology for evaluating the benefits of DOE research on fuel cells and to assess the benefits of DOE research on coal gasification
US DOE HQ	• Support of R&D program planning for hydrogen-fueled combustion turbines • Development of the potential R&D pathways to large scale advanced DC/AC inverters • Evaluation of advanced fuel cell technologies • Assessment of advanced approaches to integrate coal gasification and power production

- Critical Pre-publication Review of Draft Report on Cost and Performance Comparison of Fossil Energy Power Plants (IGCC, Conventional Coal, and Natural Gas Combined Cycle Power Plants)-DOE NETL, 2006
- Evaluation of the Results of the CCPC's Phase I Studies of Advanced Coal-Fired Power Generation Technologies for CO_2 Emissions Control and CCPC's Proposed Scope of Phase II of the Project (jointly with SFA Pacific), Canadian Clean Power Coalition, 2004
- Technology Assessment of IGCC for the Coproduction of Electricity, Chemicals, and Liquid Fuels from Various Coals – subcontractor to ERI International, 2001

- Expert Witness in Litigation Involving Coal Gasification Technology, 2001 and 2000, (Confidential Clients)
- Compilation of North American and Asian Coal Gasification R&D, EPRI Coal Fleet for Tomorrow, 2005
- Evaluation of Innovative Fossil Fuel Power Plants with CO2 Removal, 2000, EPRI (with Parsons)
- Review of R&D Required for Development of Hydrogen Fueled Turbines, DOE 2004
- Direct Carbon Fuels Cells: Assessment of their Potential as Solid Carbon Based Power Generation Systems, LLNL 2004
- Engineering Study of the Commercialization Potential of Six Pre-Combustion Coal Cleaning Technologies, FirstEnergy, 2004
- Productivity Improvement for Fossil Stream Power Plants: Industry Case Studies, EPRI 2003
- Assessment of CO2 Capture Technologies, EPRI, 2003
- RAM Statistics for 250-300 MW IGCC Demonstration Plants, EPRI, 2003
- Potential Application of Plasma Gasification Technology for Commercial Power Production from Coal, Biomass, and Waste Materials, Southern Company Services, 2003
- Status of Coal Upgrading Technologies, EPRI, 2003
- Evaluation of a Proprietary Plasma Based Gasification Technology for Power Production, Southern Company Services, 2002
- Productivity Improvement Handbook for Fossil Steam Power Plants, 3rd Edition, EPRI, 2002
- Review of DOE's Vision 21 Research and Development Program, National Research Council, 2002 (co-author)
- IGCC Power Plant RAM Analysis, EPRI, 2002
- Coal Use in Petroleum Refineries: Opportunities and Issues, 2002, EPRI
- Power Augmentation for California Gas Turbines, 2001, California Energy Commission
- Combustion Turbine Humidified Air Injection for Power Augmentation Application Study, 2001, California Energy Commission
- Combustion Turbine Humidified Air Injection for Power Augmentation Application Study, DOE (with Parsons and ESPC), 2001
- Carbon Mitigation Options for Coal Fired Power Plants, ERI, 2001
- Gas Turbine and Fuel Cell R&D Needs for Integration with Coal Gasification –Summary and assessment of the use of coal derived syngas in gas and fuel cells including recommendations for obtaining additional information, 2000, DOE NETL
- Evaluation of Fuel Cell Reformer Technology, ERI, 2000
- Evaluation of Liquid Fuel Reformer Technology, ERI, 2000
- Vision 21, Fossil Fuel Options for the Future, National Research Council (co-author), 2000
- The Status of Small PEM Fuel Cell Technology Development, DOE 1999

Employment History:	1994 – Present	Principal, Wolk Integrated Technical Services, San Jose, CA
	1980 – 1994	Director, Advanced Fossil Power Systems Department, EPRI
	1974 – 1980	Program Manager, Clean Liquid and Solid Fuels Program, EPRI
	1958 – 1974	Associate Laboratory Director, Hydrocarbon Research Inc.
Education:	M.S. Ch.E	Polytechnic Institute of Brooklyn, 1962
	B. Ch. E	Polytechnic Institute of Brooklyn, 1958

Countries of Experience: United States

Languages: English (Native)

Professional Activities/Awards:

American Institute of Chemical Engineers, Fuels and Petrochemical Division
Board of Directors, Pittsburgh Coal Conference
Board of Directors, Low Rank Coal Symposia
Hydrocarbon Research Inc. Inventors Award -- in recognition of 48 US patents
Council on Alternate Fuels- Career Achievement Award
Professional and Technical Consultant's Association -- Member of the Board of Director's (1999 and 2000) and President (2000)

Publications

Over 200 published articles, papers, patents and technical presentations at professional meetings