Sithe Global LLC
Desert Rock Energy Project
Four Corners, NM

Desert Rock Energy Project Design Comparison to Integrated Gasification Combined Cycle and Circulating Fluidized Bed Combustion

ENSR Corporation
September 2005
Document Number 10784-001-0003

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1.0 INTRODUCTION

The "Integrated Gasification Combined Cycle Compared to Desert Rock Energy Project, May 3, 2005" document focused on efficiency and financial aspects of an Integrated Gasification Combined Cycle plant located at the Desert Rock site. This report includes emission data as well as updated efficiency and financial data for an IGCC plant and a comparison to the planned Desert Rock project. In addition, this report provides a comparison of the planned Desert Rock project to a circulating fluidized bed project located at the Desert Rock site. This report replaces the May 3, 2005 report

Sithe Global Power, LLC (Sithe) is proposing to build a 1,500 MW gross (1,366 MW net) mine mouth power plant to burn sub-bituminous coal. The plant will be located in Northwestern New Mexico at an elevation of 5,415 feet. Two super critical pulverized coal fired boilers operating at a net heat rate of 8,792 Btu/kWh (higher heating value basis) are planned. Very low emission rates have been proposed for this project including 0.06 lb/MMBtu for both NOx and SO_2 and 0.01 lb/MMBtu for filterable PM.

1.1 Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) is a developing coal technology that offers the potential for improved environmental performance and high efficiency. Proponents of IGCC point to low air pollutant emissions, less solid waste, and reduced water consumption when compared to specific examples of direct coal combustion technologies. Although CO_2 capture is not currently required, the ability of IGCC to provide for easier CO_2 capture than direct coal combustion technologies may be an advantage in the future. In addition, the potential to co-produce hydrogen adds the potential to produce a clean transportation fuel. Comparisons between IGCC and direct coal combustion technologies are affected by fuel composition, assumed air pollution control methods and performance, site elevation, cooling technology and other factors. For example, IGCC heat rates increase as the ash content of the coal increases. High ash concentrations in some coals also create operating and maintenance issues to the extent that IGCC is not applicable to waste coal due to the high ash content.

Currently, there are only four operating coal-based IGCCs in the world for power generation. Two of these are demonstration plants in the United States. The two U.S. demonstration plants are single train systems consisting of one gasification process, one gas cleanup process, one combustion turbine, and one steam turbine. The demonstration plants, which are all partially supported by government and research funding, have net capacities of 250 MW (Tampa Electric Polk Power station in Florida) and 262 MW (Wabash River in Indiana). Recently, the Polk Power Plant has been operating on a 55/45 petroleum coke/coal feed and the Wabash plant has operated on 100% petroleum coke since the DOE demonstration program ended in 2000.[1] Petroleum coke is less

[1] Holt, Neville. Coal Based IGCC Plants – Recent Operating Experience and Lessons Learned. Presented at the Gasification Technologies Conference. Washington, DC. October 4-6, 2004.

expensive than coal and offers better IGCC performance and reliability due to low ash and high heating value. In late 2004, the Wabash plant was reported as not operating due to business reasons. [2]

1.2 Circulating Fluidized Bed Combustion

Circulating Fluidized Bed (CFB) combustion power plants, sub-critical pulverized coal (PC) power plants, and super critical PC (SCPC) plants are being proposed and built in the U.S... The technology choice depends on many factors including the size of the project, the types of fuel that will be burned, fuel properties, plant location, and local solid waste and water issues. In addition, the technology choice is affected by the developer's or utility's experience with the technology and their perception of technological risk and maintenance issues as well as future fuel costs and electricity prices.

There are several key differences between a CFB plant and a SCPC plant. The maximum size of CFB boiler is currently 300 MW net while PC units can be as large as 1,200 MW net. For large plants, the need for multiple CFB units adversely impacts the capital cost. Currently, all CFB plants in operation are sub critical units with significantly higher heat rates and lower efficiencies when compared to SCPC units. A supercritical CFB plant is planned to be built in Poland but there is no demonstrated experience with supercritical CFB plants. There are hundreds of SCPC plants with long operating histories. In some areas of the country, the ability of CFB plants to provide fuel flexibility and the ability to burn poor quality fuels such as petroleum coke, waste coal, and biomass is important.

[2] Holt, Neville. Coal Based IGCC Plants – Recent Operating Experience and Lessons Learned. Presented at the Gasification Technologies Conference. Washington, DC. October 4-6, 2004.

2.0 EXECUTIVE SUMMARY

The results of this study comparing IGCC and CFB to the Desert Rock Energy project lead to the following conclusions:

2.1 Integrated Gasification Combined Cycle

- IGCC is not an inherently low emitting or pollution free process. For example, a series of chemical processes are required to remove sulfur from the syngas and control SO_2 emissions. Sulfur removal typically begins with a COS hydrolysis unit to convert COS to H_2S. This is followed by either AGR processes based on aqueous dimethyldiethanolamine or the Selexol process which uses mixtures of dimthyl ethers and polyethylene glycol. A Claus sulfur plant is then required to process sulfur containing compounds collected by the AGR or Selexol process. Finally, for high sulfur removal, a Claus tail gas treating process is required. Using these processes, it is possible for an IGCC plant to achieve high SO_2 control efficiencies. The Polk Power Project has operated at over 97% SO_2 control while the Wabash River project has demonstrated 99% SO_2 control.[3, 4] IGCC plants may be able to achieve 99% SO_2 control which is a higher control efficiency than the proposed Desert Rock project that will have a removal rate of approximately 98%..

- Both the Wabash River and Polk projects have operated at NOx emission rates of approximately 0.15 lb/MMBtu or 2.5 times the proposed Desert Rock emission rate. In July 2003, the permit limit for the Wabash River project was reduced to 15 ppmvd at 15% O_2 which is approximately 0.07 lb/MMBtu based on coal feed, which is higher than the Desert Rock emission rate. This revision to Wabash emission rate was reported to represent a major challenge because neither SCR nor dry low NOx combustion can be applied to syngas fired turbines.[5]

- IGCC plants can achieve PM (filterable only) and VOC emission rates similar to the emission rates proposed for the Desert Rock project.

- CO emission rates proposed for IGCC projects are approximately 40% to 50% of the emission rate proposed for the Desert Rock project. However, the benefits of lower

[3] Tampa Electric Integrated Gasification Combined Cycle Project – Project Performance Summary, US DOE, June 2004

[4] Wabash River Coal Gasification Repowering Project – Project Performance Summary, US DOE, June 2002

[5] Wabash River Coal Gasification Repowering Project – Project Performance Summary, US DOE, June 2002

CO emissions are insignificant because ambient impacts are insignificant and CO is converted to CO_2 in the atmosphere within about 30 days.

- IGCC plants can achieve lower mercury emission rates than required for the proposed Desert Rock PC project.

- The heat rate for an IGCC plant would be adversely affected by fuel composition. Then heat rate for an IGCC plant is estimated as 9,775 Btu/kWh while the estimated heat rate for Desert Rock is 8,792 Btu/kWh (net, higher heating value basis).

- IGCC plants do not have the same economies of scale as the planned super critical boilers. The Desert Rock project will consist of two 750 MW (gross) trains with each train including a single boiler, an air pollution control system and a steam turbine generator. An IGCC plant capable of achieving the same power output would consist of three trains with each train including two air separation units, four gasifiers (one is a spare), two gas cleanup systems, two GE FA gas turbines with HRSGs, and a steam turbine. In addition, some arrangement for an additional GE7 FA and HRSG would be needed for an IGCC to achieve the required power output at the site elevation of 5,415 feet. In total, an IGCC plant would require six air separation units, twelve gasifiers, six gas cleanup systems, seven GE7FA gas turbines with HRSGs, and three steam turbines.

- Capital costs for an IGCC plant would be adversely affected by the Desert Rock fuel properties and site location. Capital costs for an IGCC plant, with spare gasifiers, would exceed the Desert Rock costs by $250/kW to $400/kW. This represents a capital cost increase of $350 million to $600 million or 17% to 28%.

- The cost of electricity for an IGCC plant would be $3.5/MWh to $6/MWh higher than the planned Desert Rock project. As an SO_2 control method this cost increase is equivalent to $23,000 to $40,000 per ton of SO_2 controlled.

- IGCC plants have lower availability than SCPC plants, especially in the early years of operation and they are more prevalent to incidents of forced outage as operations of the plants mature. The analysis presented in this study assumes that a spare gasifier for each IGCC train will mitigate this problem. However, there is no demonstrated experience showing that a spare gasifier will eliminate the reliability problems that have been experienced. Therefore, there may be additional costs associated with lost electricity production and/or a need for a firm natural gas supply. These potential additional costs have not been quantified.

- The technology risk of building an IGCC plan might make the plant less desirable to utility investors and power purchasers. The increased risk would also increase financing costs, as lenders will want more equity and higher maintenance and debt coverage reserves. These factors will increase the total capital cost.

- Should it ever be technically viable, CO_2 capture in an IGCC plant would increase the heat rate by 20% to 30%, increase the capital cost by an additional $550/kW, and increase the cost of electricity by an additional 35% to 47%.

- IGCC is not a commercially viable option for the Desert Rock site.

2.2 Circulating Fluidized Bed Combustion

- Five or six CFB units would be required instead of two SCPC units to achieve the planned Desert Rock power output. The loss of economy of scale would significantly increase the capital and operational costs of a CFB plant.

- On a lb/MMBtu basis, most emissions from a CFB plant would be similar to the planned SCPC plant.

- The heat rate for a CFB plant would be about 9,950 Btu/kWh while the heat rate for Desert Rock is 8,792 Btu/kWh (net, higher heating value basis). For the same net electricity production and emission rates, a CFB plant would generate 11% more emissions than Desert Rock, including CO2 emissions.

- On an annual ton/yr basis, all emissions from a CFB plant would be higher than the planned SCPC plant due to the higher heat rate.

- Based on annual emissions, a SCPC plant is the preferred technology.

3.0 AIR POLLUTANT EMISSIONS

Technical papers, conference proceedings, and permit data were reviewed to determine air pollutant emission rates that might be achievable by a new, well designed IGCC plant and a CFB plant. The results of this analysis are summarized in Table 1 and discussed in more detail in this section.

3.1 Integrated Gasification Combined Cycle

3.1.1 IGCC - Sulfur Dioxide Emissions (SO_2)

Sulfur dioxide emissions from an IGCC plant are controlled by removing sulfur compounds from the syngas before it is burned. There are numerous chemical solvent processes, physical solvent process and mixed chemical/physical processes that are commercially available.[6] These processes have been applied for many years in the natural gas industry. After the sulfur is removed from the syngas a Claus sulfur recovery plant or a sulfuric acid plant is required to recover the sulfur. Tail gas treatment on the Claus sulfur recovery plant or a sulfuric acid plant is required to limit SO_2 emissions. SO_2 control from an IGCC plant requires significant capital and operating costs.

Both the Polk Power Station and Wabash River IGCC plants have typically operated at SO_2 emission rates in the 0.1 to 0.2 lb/MMBtu range. The Polk Power Project has operated at over 97% SO_2 control while the Wabash River project has demonstrated 99% SO_2 control.[7, 8]

Permit limits for new plants are:

- Elm Road, Wisconsin – 0.03 lb/MMBtu
- Lima Energy, Ohio – 0.021 lb/MMBtu
- Kentucky Pioneer – 0.032 lb/MMBtu

Southern Illinois Energy has proposed a BACT emission limit of 0.033 lb/MMBtu based on 99.4% control. The BACT analysis for this facility states that that the proposed emission rate is lower than

[6] Korens., N., et.al. Process Screening Analysis of Alternative Gas treating and Sulfur Removal for Gasification. Prepared by SEA Pacific, Inc. for the US Department of Energy, Revised Final Report December 2002.

[7] Tampa Electric Integrated Gasification Combined Cycle Project – Project Performance Summary, US DOE, June 2004

[8] Wabash River Coal Gasification Repowering Project – Project Performance Summary, US DOE, June 2002

achieved in practice at any IGCC facility. In addition, Southern Illinois Energy's analysis showed that higher control efficiencies are not BACT due to high costs and lack of operating experience[9].

None of the four recently proposed IGCC plants with low proposed SO_2 emission rates have been built and at least some will not be built. The Elm Road IGCC plant was proposed by Wisconsin Electric which is a regulated utility. However, the Elm Road project was rejected by the Wisconsin Public Service Commission based on not being cost effective. Wisconsin regulators were not willing to have their customers subsidize IGCC development.[10] Therefore, greater than 99% control has not been demonstrated to be technically or economically achievable on a long term basis by applying IGCC technology.

For comparison to the proposed Desert Rock Project, it is assumed that an IGCC plant might be able to achieve 99% control of SO_2 emissions while operating on the Desert Rock fuel. At this level of control SO_2 emissions would theoretically be 0.023 lb/MMBtu and 1,272 ton/yr compared to 0.06 lb/MMBtu as a 24-hour average and 2,998 ton/yr for the Desert Rock project as shown in Table 1[11]. However, as discussed in Section 4 the cost of electricity would be \$3.5/MWh to \$6/MWh higher than the planned Desert Rock project. As an SO_2 control method this cost increase is equivalent to \$23,000 to \$40,000 per ton of SO_2 controlled (it would cost \$40 million/yr to \$68 million/yr to reduce SO_2 emissions by 1,726 ton/yr). Therefore, IGCC is not a cost effective method to control SO_2 emissions at the Desert Rock site.

3.1.2 IGCC - NOx Emissions

NOx emissions from an IGCC plant are controlled by removing ammonia and hydrogen cyanide from the syngas and using nitrogen or steam as diluents in the gas turbine.[12]

The Wabash River and Polk projects have operated at NOx emission rates of approximately 0.15 lb/MMBtu. In July 2003, the permit limit for the Wabash River project was reduced to 15 ppmvd at 15% O_2 which is approximately 0.07 lb/MMBtu to 0.08 lb/MMBtu based on coal feed. This revision

[9] Southern Illinois Clean Energy Center Air Permit Application, Appendix E, Best Available Control Technology Analysis. October 2004.

[10] Wisconsin Energy Proposed IGCC Plant Lessons Learned. Presented at the Clean Coal Roundtable, Washington DD, July 2004.

[11] The Desert Rock SCPC annual potential to emit presented in the PSD permit application is based on the a probable worst case one hour operating condition. The power output and heat rate in this table is based on a annual average operating condition. Therefore, the annual potential to emit in the PSD permit application is approximately 10% higher.

[12] Major Environmental Aspects of Gasification-Based Power Generation Technologies. US Department of Energy. December 2002.

to Wabash emission rate was reported to represent a major challenge because neither SCR nor dry low NOx combustion can be applied to syngas fired turbines. [13]

Recently proposed emission rates for IGCC projects are compared to the Desert Rock emission rate in Table 2.[14] The only NOx control method currently proposed for IGCC is diluent injection. Using diluent injection, IGCC may be able to achieve the NOx emission rate proposed for the Desert Rock project.

For comparison to the proposed Desert Rock Project, it is assumed that an IGCC plant might be able to achieve a NOx emission rate of 0.06 lb/MMBtu based on as fired coal. However, there are no IGCC plants that have achieved this emission rate. At 0.06 lb/MMBtu, NOx emissions from an IGCC plant would be 3,333 ton/yr compared to 2,998 ton/yr for the Desert Rock project as shown in Table 1. IGCC is not an effective method to control NOx emissions because it results in higher emissions than the planned Desert Rock SCPC.

3.1.3 IGCC - PM_{10} Emissions

PM_{10} emissions from an IGCC plant are controlled by either high temperature candle type barrier filters or warm gas wet scrubbers that are used to clean the syngas prior to the gas turbine. In an IGCC plant, char and ash must be removed from the syngas to protect the gas turbine. Because data are generally not available for condensable PM_{10}, this section only addresses filterable PM_{10}.

Recently proposed emission rates for IGCC projects are compared to the Desert Rock emission rate in Table 3.[15] Table 3 shows that proposed IGCC emission rates are similar to the Desert Rock project.

For comparison to the proposed Desert Rock Project, it is assumed that an IGCC plant might be able to achieve a filterable PM_{10} emission rate of 0.10 lb/MMBtu based on as fired coal. At 0.10 lb/MMBtu, PM_{10} emissions from an IGCC plant would be 556 ton/yr compared to 500 ton/yr for the Desert Rock project as shown in Table 1. IGCC is not an effective method to control PM_{10} emissions because it results in higher emissions than the planned Desert Rock SCPC.

[13] Wabash River Coal Gasification Repowering Project – Project Performance Summary, US DOE, June 2002

[14] It should be noted that reported PM10 emission rates, as well as emission rates for other pollutants, are sometimes based on the amount of syngas combusted not the coal feed rate. Because syngas represents 70% to 90% of the coal feed heat input, NOx emission rates as lb per MMBtu of coal are higher than the reported lb per MMBtu of syngas.

[15] It should be noted that reported NOx emission rates, as well as emission rates for other pollutants, are sometimes based on the amount of syngas combusted not the coal feed rate. Because syngas represents 70% to 90% of the coal feed heat input, NOx emission rates as lb per MMBtu of coal are higher than the reported lb per MMBtu of syngas.

3.1.4 IGCC - VOC Emissions

VOC emissions from an IGCC plant are controlled by good combustion. Recently proposed emission rates for IGCC projects are compared to the Desert Rock emission rate in Table 4. Table 4 shows that there are wide variations in proposed IGCC VOC emission rates. Because none of these facilities has been built it is difficult to determine the level of VOC emissions that may be achievable.

For comparison to the proposed Desert Rock Project, it is assumed that an IGCC plant might be able to achieve a VOC rate of 0.0030 lb/MMBtu based on as fired coal. At 0.0030 lb/MMBtu. VOC emissions from an IGCC plant would be 167 ton/yr compared to 150 ton/yr for the Desert Rock project as shown in Table 1. IGCC is not an effective method to control VOC emissions because it results in higher emissions than the planned Desert Rock SCPC.

3.1.5 IGCC - CO Emissions

CO emissions from an IGCC plant are controlled by good combustion. Recently proposed emission rates for IGCC projects are compared to the Desert Rock emission rate in Table 5. Table 5 shows that proposed CO emissions rates for IGCC plants are typically below 0.04 lb/Btu.

For comparison to the proposed Desert Rock Project, it is assumed that an IGCC plant might be able to achieve a CO rate of 0.040 lb/MMBtu based on as fired coal. At 0.040 lb/MMBtu, CO emissions from an IGCC plant would be 2,222 ton/yr compared to 4,997 ton/yr for the Desert Rock project at 0.10 lb/MMBtu as shown in Table 1. However, there is very little if any environmental benefit from controlling CO emissions from power plants for two reasons. First, the ambient impacts associated with CO emissions from power plants are insignificant. Second, CO is reduced in power plants by oxidizing this intermediate combustion product to CO_2. However, if CO is emitted it is oxidized to CO_2 in the atmosphere within a couple of months. Therefore, control of CO simply speeds up the oxidation to CO_2.

3.1.6 IGCC - Sulfuric Acid Mist Emissions

Sulfuric acid mist emissions from an IGCC plant are controlled by removing sulfur compounds from the syngas before it is burned see the discussion in Section 3.1. The only recently proposed IGCC permit limits are 0.0042 lb/MMBtu for the Southern Illinois project and 0.005 lb/MMBtu for the Elm Road project.

For comparison to the proposed Desert Rock Project, it is assumed that an IGCC plant based on the Desert Rock fuel might be able to achieve a sulfuric acid mist emission rate of 0.0023 lb/MMBtu which would be 10% of the SO_2 emission rate. At 0.0023 lb/MMBtu, sulfuric acid mist emissions from an IGCC plant would be 128 ton/yr compared to 200 ton/yr for the Desert Rock project as shown in Table 1. However, as discussed in Section 4 the cost of electricity would be at least $3/MWh to $5/MWh higher than the planned Desert Rock project. As an sulfuric mist control method this cost increase is equivalent to more than $500,000 per ton of sulfuric acid mist controlled. Therefore, IGCC is not a cost effective method to control sulfuric acid mist emissions at the Desert Rock site.

3.1.7 IGCC - Mercury Emissions

Mercury emissions from an IGCC plant are controlled by removing mercury from the syngas before it is burned. Mercury is removed by adsorption on activated carbon beds. The process that might be used to regenerate the activated carbon is complex and expensive. Therefore, used activated carbon requires disposal as a hazardous waste. The technology for mercury controlled as been widely used on natural gas and has shown very high efficiencies. The air permit for the Elm Road IGCC project requires 95% mercury capture.

For comparison to the proposed Desert Rock Project, it is assumed that an IGCC plant based on the Desert Rock fuel might be able to achieve 95% mercury capture. At 95% mercury capture, mercury emissions from an IGCC plant would be 29 lb/yr compared to 103 lb/yr for the Desert Rock project as shown in Table 1. However, as discussed in Section 4 the cost of electricity would be at least $3.5/MWh to $6/MWh higher than the planned Desert Rock project. As an mercury control method this cost increase is equivalent to more than $500,000 per pound of mercury controlled. Therefore, IGCC is not a cost effective method to control mercury emissions at the Desert Rock site.

3.2 Circulating Fluidized Bed Combustion

Emission rates for a circulating fluidized bed (CFB) combustion were derived from the PSD permit for the 270 Mw Sevier Power Company project in Utah. Note that one reason for the selection of a CFB was probably the size of the project. Only one power production train is required for 270 MW but multiple trains are required for higher power capacity. This permit for Sevier was issued on October 12, 2004 and represents the current emission performance for the CFB technology. Since October 2004, PSD permits have been issued for Greene Energy in Pennsylvania and Gascoyne in North Dakota. However, these two permits are not relevant because the Greene Energy project will burn waste coal and the Gascoyne project will burn lignite. Table 6 presents a summary of potential CFB emission rates at the Desert Rock site and a comparison to the proposed Desert Rock project. All of the potential emissions from a CFB plant at the Desert Rock site exceed the expected emissions from the planned SCPC plant. Therefore, using CFB technology at the Desert Rock site is not an effective method to control emissions.

3.2.1 CFB – SO_2 Emissions

In a CFB, the primary SO_2 emission control is accomplished by reacting SO_2 with calcined limestone in the fluidized bed. In some cases, additional SO_2 control is achieved by a dry SO_2 scrubber used as a polishing scrubber. The dry scrubber may be a spray dryer absorber, a circulating dry scrubber, or an alternative but similar technology. The Sevier project will use a circulating dry scrubber.[16]

The PSD permit limits for the Sevier project are 0.05 lb/MMBtu as a 24-hr average and 0.022 lb/MMBtu as a 30-day average.[17] However, on a lb/MMBtu basis the Desert Rock fuel contains 2.62 times as much sulfur as the Sevier fuel. Therefore, the expected 30-day average or long term emission rate for a CFB at the Desert Rock site is 0.0576 lb/MMBtu. Because the heat rate for CFB plant is higher the SCPC plant planned for the Desert Rock site, annual SO_2 emissions from a CFB plant would be higher than the planned project. As shown in Table 6, SO_2 emissions from a CFB plant would be 3,258 ton/yr compared to 2,998 ton/yr for the planned SCPC project.

3.2.2 CFB – NOx Emissions

In a CFB, NOx emission control is accomplished through low combustion temperatures, staged combustion and selective non-catalytic reduction. Selective catalytic reduction is not used on CFB plants due to high particulate concentrations associated with the required temperature window for SCR. These NOx control methods will be used by the Sevier project.

The PSD permit limit for the Sevier project 0.10 lb/MMBtu as a 24-hr average which is much higher than the Desert Rock proposed emission limit of 0.06 lb/MMBtu as a 24-hr average. Annual NOx emissions from a CFB plant would be much higher than the planned project. As shown in Table 6, NOx emissions from a CFB plant would be 5,956 ton/yr compared to 2,998 ton/yr for the planned SCPC project.

3.2.3 CFB – PM_{10} Emissions

PM_{10} emissions form both CFB and SPCP plants are typically controlled by bag houses. Only limited and variable information is available on total PM_{10} emissions including condensable PM_{10}. Therefore, this comparison is based on filterable PM_{10} emissions. Filterable PM_{10} emissions for CFBs are in the 0.010 to 0.018 lb/MMBtu range. Although PM_{10} emissions from a CFB before control are expected to be higher than from a SCPC, bag houses applied to these technologies are expected to achieve similar emission rates on a lb/MMBtu basis.

[16] New Source Plan Review. Utah Division of Air Quality. December 23, 2003.

[17] Approval Order: Sevier Power Company's 270 MW Coal-Fired Power Plant. DAQE-AN2529001-04. State of Utah Department of Environmental Quality. October 12, 2004.

For comparison to the Desert Rock SCPC project, it is assumed that a CFB project could achieve a filterable PM_{10} emission rate of 0.01 lb/MMBtu. Because the heat rate for a CFB plant is higher than the SCPC plant planned for the Desert Rock site, annual PM_{10} emissions from a CFB plant will be higher than the planned project. As shown in Table 6, filterable PM_{10} emissions from a CFB plant would be 566 ton/yr compared to 500 ton/yr for the planned SCPC project.

3.2.4 CFB – VOC Emissions

In a CFB, VOC emission control is accomplished with good combustion practices. The Sevier project will use good combustion practices.

The BACT analysis for the Sevier project indicates a VOC emission rate of 0.005 lb/MMBtu which is higher than the proposed Desert Rock emission rate of 0.003 lb/MMBtu. Therefore, annual VOC emissions from a CFB plant would be higher than the planned project. As shown in Table 6, VOC emissions from a CFB plant would be 283 ton/yr compared to 150 ton/yr for the planned SCPC project.

3.2.5 CFB – CO Emissions

In a CFB, CO emission control is accomplished with good combustion practices. Typical CO permit limits for a CFB are in the 0.10 lb/MMBtu to 0.15 lb/MMBtu range. The Sevier project will use good combustion practices to control CO emissions.

The CO permit limit for the Sevier project is 0.115 lb/MMBtu which is higher than the proposed Desert Rock emission rate of 0.10 lb/MMBtu. However, based on other permits, it is assumed that a CFB plant might be able to achieve 0.10 lb/MMBtu. As shown in Table 6, CO emissions from a CFB plant would be 5,565 ton/yr compared to 4,997 ton/yr for the planned SCPC project.

3.2.6 CFB – Sulfuric Acid Mist Emissions

In a CFB, sulfuric acid mist emissions are controlled by reactions with calcined limestone in the fluidized bed and fabric filtration. In some cases, additional control is achieved by a dry SO_2 scrubber used as a polishing scrubber. The dry scrubber may be a spray dryer absorber, a circulating dry scrubber, or an alternative but similar technology. The Sevier project will use a circulating dry scrubber.

The PSD permit limit for the Sevier project is 0.00024 lb/MMBtu as a 24-hr average and 0.022 lb/MMBtu as a 30-day average.[18] However, on a lb/MMBtu basis the Desert Rock fuel contains 2.62

[18] Approval Order: Sevier Power Company's 270 MW Coal-Fired Power Plant. DAQE-AN2529001-04. State of Utah Department of Environmental Quality. October 12, 2004.

times as much sulfur as the Sevier fuel. Therefore, the expected emission rate for a CFB at the Desert Rock site is 0.0063 lb/MMBtu.   As shown in Table 6, sulfuric acid mist emissions from a CFB plant would be 356 ton/yr compared to 200 ton/yr for the planned SCPC project.

3.2.7 CFB – Mercury Emissions

On a lb/MMBtu basis, there is no available information showing a difference between a CFB plant and a SCPC plant. However at the same lb/MMBtu emission rate, annual mercury emissions from a CFB will be higher due to the lower heat rate. As shown in Table 6, mercury emissions from a CFB plant would be 103 lb/yr compared to 105 ton/yr for the planned SCPC project.

4.0 PERFORMANCE AND COST COMPARISON

The expected performance and cost to apply IGCC at the Desert Rock site has been estimated from published data and studies. In general most of these studies have focused on higher sulfur Eastern and Midwestern coals such as Pittsburgh # 8 and frequently Illinois # 8 and not on western coals that are not as well suited to this technology. In addition, available cost estimates are projections that are not based on actual demonstrated experience with the expected design. Instead, the cost estimates typically include assumptions that the next plants will perform better and be less costly than the currently operating plants. All cost estimates indicate that the capital cost and cost of electricity for an IGCC plant will be significantly higher than a SCPC plant in the near term.

4.1 Heat Rate and Efficiency

The expected average heat rate for the Desert Rock project is 8,792 Btu/kWh based on the fuel higher heating value and net plant output. The corresponding efficiency is 38.8%.

The predicted average heat rate for a new 500 MW IGCC plant based on the E-gas process and operating on Pittsburgh #8 coal with a heating value of 13,260 Btu/lb, ash content of 7.1%, and 2.1% sulfur is 8,630 Btu kWh net based on the fuel higher heating value.[19] However, the lower fuel heating value of the Desert Rock fuel, which is 8,953 Btu/lb, will have an adverse effect on heat rate as shown in Figure 1. The expected heat rate for the Desert Rock coal is 13% greater than Pittsburgh #8 coal or 9,775 Btu/kWh. The corresponding efficiency is 34.9%.

Heat rates for CFB plants are significantly higher than SCPC plants, in part, because all operating CFB plants are sub critical plants. Most published heat rates for CFB plants are slightly below 10,000 Btu/kWh (net, higher heating value). A typical example is the expected heat rate for the JEA project in Florida which was 9,950 Btu/kWh.[20] For comparison to the planned SCPC project a CFB heat rate of 9,950 Btu/kWh is assumed.

4.2 Capital Costs

The Desert Rock project will consist of two 750 MW (gross) trains with each train including a single boiler, an air pollution control system and a steam turbine generator.

An IGCC plant capable of achieving the same power output would consist of three trains with each train including two air separation units, four gasifiers (one is a spare), two gas cleanup systems, two

[19] Booras, G. and N. Holt. Pulverized Coal and IGCC Plant Cost and Performance Estimates. Presented at Gasification Technologies 2004, Washington, DC., October 3-6, 2004

[20] www.netl.doe.gov/cctc/summaries/jacks/jackeademo.html

GE FA gas turbines with HRSGs and a steam turbine. Global Energy suggests two 50% capacity gasifiers for Pittsburgh #8 coal but three 33% capacity gasifiers for sub bituminous coal.[21] A spare gasifier is needed to provide 90% availability. In addition, at the site elevation of 5,415 feet, the power output of a GE7FA would be reduced by approximately 20%.[22] Therefore, some arrangement for an additional GE7 FA and HRSG would be needed for an IGCC plant to achieve the required power output at the site elevation of 5,415 feet. In total, an IGCC plant would require six air separation units, twelve gasifiers, six gas cleanup systems, seven GE7FA gas turbines with HRSGs, and three steam turbines.

In general, current total capital costs for a 600 MW IGCC plant, with a spare gasifier, operating on Pittsburgh #8 coal are recognized to be 10% to 30% higher than a supercritical PC plant. WePower, working with Flour Daniel and Bechtel, estimated capital costs of $1,579/kW for an IGCC plant and $1,400 for a SCPC plan, a difference of $179/kW.[23] However, according to WePower, the project was rejected because regulators were not willing to have their customers subsidize IGCC development. AEP has estimated the cost for an IGCC plant in Ohio at $1,750/kW compared to $1,400/kW for a PC plant, a difference of $300/kW.[24] However, the Ohio Consumer's Counsel is asking Ohio regulators to reject AEP's request to guarantee cost recovery for their IGCC project.[25]

EPRI has estimated the total capital requirement for a 500 MW IGCC plant, with a spare gasifier, operating on Pittsburgh #8 coal as $1,610/kW. [26] However, EPRI also estimates that the IGCC costs would increase by 20% while PC costs would increase by 12% for a coal heating value similar to the Desert Rock coal, approximately 9,000 Btu/lb, see Figure 1. Therefore, the adjusted EPRI estimates would be $1,932/kW for IGCC and $1,678/kW for a PC plant, a difference on $254/kW.

In an earlier, less detailed technical paper by the same EPRI authors, it was reported that IGCC total capital costs for sub bituminous coals and lignite, without CO_2 capture, were expected to be $300 to $400/kW higher than a PC plant.[27]

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[21] Breton, D. L. and P. Amick. Comparative IGCC Cost and Performance for Domestic Coals. @002 Gasification Conference. October 28, 2002.

[22] Brroks, F. J. GE Gas turbine Performance Characteristics. General Electric Publication GER-3567H.

[23] Wisconsin Energy Proposed IGCC Plant Lessons Learned. Coal Roundtable. Washington, DC. July 2004.

[24] Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995.

[25] http://www.platts.com/Magazines/POWER/Power%20News/2005/051005_7.xml

[26] Booras, G. and N. Holt. Pulverized Coal and IGCC Plant Cost and Performance Estimates. Presented at Gasification Technologies 2004, Washington, DC., October 3-6, 2004

[27] Holt, N., G. Booras, and D. Todd. A summary of Recent IGCC Studies of CO_2 Capture for Sequestration. Presented at the Gasification Technologies Conference. San Francisco, CA. October 12-15, 2003.

The capital cost for an IGCC plant at the Desert Rock site will also be adversely affected by the high ash content of the coal and the altitude which is 5,415 ft. On a lb/MMBtu basis, the Desert Rock coal contains approximately 4 to 5 times as much ash as Pittsburgh #8 coal. The higher ash content will increase costs for material handling equipment as well as measures needed to prevent erosion and corrosion of equipment. At the sit elevation of 5,415 ft, air is 20% less dense than at sea level. As previously mentioned, this will decrease the power output of each gas turbine by 20% and require an additional gas turbine to achieve the planned power output. Also, because the air contains 20% less oxygen on a lb cubic foot basis larger or additional air separation units would be needed.

Based on available information as presented above, total capital investment for IGCC at the Desert Rock site would be at least $250/kW greater than the planned SCPC plant and could be as much as $400/kW greater. The increased cost to the project would be $375 million to $600 million or approximately 17% to 28% of the expected SCPC project cost.

For a 1,500 MW project, the capital cost of a 5 to 6 unit CFB plant is expected to be higher than a 2 unit SCPC. The operations and maintenance costs are also expected to be much higher. However, data to quantify these differences are not available.

4.3 Cost of Electricity

As discussed above, at the Desert Rock site the efficiency of an IGCC plant would be lower than the planned SCPC plant and the capital cost would be higher.

EPRI has estimated the cost of electricity for an IGCC plant as $3.3/MWh higher than a SCPC plant ($49.9/kWh compared to $46.6/kWh) [28]. The adverse effects of using the Desert Rock coal and the site elevation, which affect IGCC much more than the SCPC plant, would increase the cost differential. A published estimate for sub bituminous coal reports that IGCC would cost $4 to $10/MWh more than a conventional coal plant.[29]

In view of the lower efficiency and higher capital costs associated with applying IGCC at the Desert Rock site and published cost of electricity estimates, it is likely that the cost of electricity for an IGCC plant would be at least $3.5/MWh higher than the SCPC plant and could be as much as $6/MWh higher.

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[28] Booras, G. and N. Holt. Pulverized Coal and IGCC Plant Cost and Performance Estimates. Presented at Gasification Technologies 2004, Washington, DC., October 3-6, 2004

[29] Coal Gasification – Air Pollution and Permitting Implications of IGCC. USEPA Air Innovations Conference. August 10, 2004.

For a 1,500 MW project, the cost of electricity for a 5 to 6 unit CFB plant with a heat rate of 9,950 Btu/kWh is expected to be higher than a 2 unit SCPC plant with a heat rate of 8,792 Btu/kWh. However, data to quantify this difference are not available.

4.4 Reliability and Availability

The reliability and availability of IGCC plants have been continuing problem areas. The next generation of plants is expected to achieve better availability. One option to increase availability is to include a spare gasifier. However, availability equivalent to a PC boiler has not been demonstrated. Concerns about reliability and the associated financial risks is one of he reasons that the next generation of IGCC plants are expected to require cost recovery guarantees from the Federal government or public utility regulators. The analysis presented in this study assumes that a spare gasifier for each IGCC train will mitigate this problem. However, there is no demonstrated experience showing that a spare gasifier will eliminate the reliability problems that have been experienced. Therefore, there may be additional costs associated with lost electricity production and/or a need for a firm natural gas supply. These potential additional costs have not been quantified

The reliability and availability of a CFB plant are expected to be similar to a SCPC plant.

4.5 CO_2 Capture

One advantage of IGCC is the possibility of CO_2 capture and sequestration at a lower cost than can be achieved on a PC plant. However, CO_2 capture is not an inherent feature of IGCC and is neither inexpensive nor technically feasible by demonstration on a power plant.

The process of CO_2 capture in an IGCC begins with the water-gas-shift reaction where carbon monoxide in the syngas is reacted with steam to produce H2 and CO_2. Physical solvents are then used to remove reduced sulfur compounds and then CO2. The H2S is then recovered and used to produce sulfur. The CO_2 is recovered by depressurization and then compressed to 150 psig for pipeline transmission to a suitable geologic formation. The H2 rich gas is burned in the gas turbine.

The high efficiencies often cited to IGCC do not include CO_2 capture. CO_2 capture increases the heat rate of an IGCC plant by 20% to 30% to approximately 10,500 Btu/kWh to 11,500 Btu/kWh and decreases the efficiency.[30] The efficiency of an IGCC plant with CO_2 capture will be significantly less than the typical PC plant currently operating and will require more coal.

[30] Williams, R. W. IGCC: The Nest Step on the Path to Gasification Based Energy from Coal. Princeton Environmental Institute, Princeton University. November 2004.

Including CO_2 capture in an IGCC plant will increase the capital cost by approximately $300 to $400/kW. [31] [32] For sub bituminous coal, the capital cost increase for CO_2 capture is estimated to be $550/kWh. [33]

Finally, the cost of electricity produced by an IGCC plant will increase by 35% to 47% with CO_2 capture. [34]

The components of a potential IGCC CO_2 capture system are well researched and documented but an IGCC plant including CO_2 capture has never been built. In addition, only research on CO_2 storage has been conducted. Many “megascale” CO_2 storage demonstration projects are required over the next 10 to 15 years to determine the viability of CO_2 storage. [35]

CO_2 sequestration is not an option that can be considered for a commercial power plant in a competitive environment.

[31] Booras, G. and N. Holt. Pulverized Coal and IGCC Plant Cost and Performance Estimates. Presented at Gasification Technologies 2004, Washington, DC., October 3-6, 2004

[32] Williams, R. W. IGCC: The Nest Step on the Path to Gasification Based Energy from Coal. Princeton Environmental Institute, Princeton University. November 2004.

[33] Booras, G. and N. Holt. Pulverized Coal and IGCC Plant Cost and Performance Estimates. Presented at Gasification Technologies 2004, Washington, DC., October 3-6, 2004

[34] Booras, G. and N. Holt. Pulverized Coal and IGCC Plant Cost and Performance Estimates. Presented at Gasification Technologies 2004, Washington, DC., October 3-6, 2004

[35] Booras, G. and N. Holt. Pulverized Coal and IGCC Plant Cost and Performance Estimates. Presented at Gasification Technologies 2004, Washington, DC., October 3-6, 2004

Table 1 Proposed Desert Rock Emission Comparison to a New IGSS Plant

Parameter	Desert Rock [(a)]	IGCC	Units	Comments
Average Heat rate	8,792	9,775	Btu/kWh	Net heat rate based on HHV. IGCC based on 8,630 Btu/kWh for Pittsburgh #8 and 13% increase to account for coal composition (see Section 4.1)
SO2 emissions	0.060	0.0229	lb/MMBtu	99% control assumed for IGCC (fuel is 0.82% S, 8,550 Btu/lb)
SO2 emissions	2,998	1,272	ton/yr	1,366 MW and 95% capacity factor
Difference		(1,726)	ton/yr	IGCC emissions are lower than SCPC
NOx emissions	0.060	0.060	lb/MMBtu	
NOx emissions	2,998	3,333	ton/yr	1,366 MW and 95% capacity factor
Difference		335	ton/yr	IGCC emissions are higher than SCPC
PM10 emissions	0.010	0.010	lb/MMBtu	Filterable PM10 only, no condensable PM10 data are available for IGCC
PM10 emissions	500	556	ton/yr	1,366 MW and 95% capacity factor
Difference		56	ton/yr	IGCC emissions are higher than SCPC
VOC emissions	0.0030	0.0030	lb/MMBtu	
VOC emissions	150	167	ton/yr	1,366 MW and 95% capacity factor
Difference		13.5	ton/yr	IGCC emissions are higher than SCPC
CO emissions	0.10	0.040	lb/MMBtu	
CO emissions	4,997	2,222	ton/yr	1,366 MW and 95% capacity factor
Difference		(2,775)	ton/yr	IGCC emissions are lower than SCPC
Sulfuric acid mist emissions	0.0040	0.0023	lb/MMBtu	
Sulfuric acid mist emissions	200	128	ton/yr	1,366 MW and 95% capacity factor
Difference		(72)	ton/yr	IGCC emissions are lower than SCPC
Mercury emissions	9.28E-06	2.52E-06	lb/MWh	Desert Rock based on 80% control. IGCC based on 95% control. Both based on an average mercury concentration in coal of 0.046 ppm.
Mercury emissions	103	29	lb/yr	1,366 MW and 95% capacity factor
Difference		(75)	lb/yr	IGCC emissions are lower than SCPC

(a) The Desert Rock SCPC annual potential to emit presented in the PSD permit application is based on the a probable worst case one hour operating condition. The power output and heat rate in this table is based on a annual average operating condition. Therefore, the annual potential to emit in the PSD permit application is approximately 10% higher.

Table 2 Proposed Desert Rock NOx Emission Comparison to Recent Proposed IGCC Plants

Project	Emission Rate (a)		Emission Control Method	Reference	Comments
Desert Rock Power Project (NM)	0.060	lb/MMBtu as a 24-hr average	SCR	Permit application	
Southern Illinois Clean Energy Center/Steelhead Energy LLC (IL)	0.059	lb/MMBtu as a 30-day average	diluent injection	Southern Illinois October 2004 BACT analysis [b]	NOx limit is reported as 15 ppmvd at 15% O2 . SCR reported to be too expensive to be BACT.
Elm Road Generating Station (WI)	0.070	lb/MMBtu as a 30-day average	diluent injection	January 14, 2004 Wisconsin air permit [c]	15 ppmvd at 15% O2 is cited in the air permit. The project developers report 0.07 lb/MMBtu
Kentucky Pioneer Power (KY)	0.074	lb/MMBtu	diluent injection	Southern Illinois October 2004 BACT analysis [b]	
Lima Energy (OH)	0.097	lb/MMBtu	diluent injection	Southern Illinois October 2004 BACT analysis [b]	
Wabash River	0.150	lb/MMBtu		Southern Illinois October 2004 BACT analysis [b] and DOE/FE-0448 [d].	Actual emissions
Polk Power Station	0.070	lb/MMBtu	diluent injection	Southern Illinois October 2004 BACT analysis [b] and DOE/FE-0469 [e].	Permit limit was revised to 15 ppmvd at 15% O2, required to be met by July 2003. Actual emissions prior to revision were above 0.10 lb/MMBtu.
Mesaba Energy Project	0.059	lb/MMBtu	diluent injection	Excelsior Energy Presentation[f]	In a July 2004 presentation, Excelsior indicated that the NOx emission rate would be 0.041 lb/MMBtu. In a June 15, 2005 presentation Conoco Phillips (the technology supplier) indicated that emissions would be 0.060 lb/MMBtu.[g]

(a) Some IGCC emission rates may be based on heat input to the gas turbine. Emission rates based on coal feed might be 10% to 30% higher.

(b) Southern Illinois Clean Energy Center Air Permit Application, Appendix E, Best Available Control Technology Analysis. October 2004.

(c) Elm Road Generating Station Air Pollution Control Construction Permit 4530-1, Wisconsin DNR, January 14, 2004.

(d) Wabash River Coal Gasification Repowering Project – Performance Summary, US DOE Report No DOE/FE-0448, June 2002

(e) Tampa Electric Integrated Gasification Combined Cycle Project – Performance Summary, US DOE Report No. DOE/FE-0469, June 2004

(f) Why IGCC? The Mesaba Energy Project. Energy, Innovation, and Economic Development, Minneapolis, MN, June 21, 2005.

(g) E gas technology for Coal Gasification. Indiana Utility Regulatory Commission, June 15, 2005 presentation by Conoco Phillips

Table 3 Proposed Desert Rock Filterable PM10 Emission Comparison to a Recent Proposed IGCC Plant

Project	Emission Rate (a)		Emission Control Method	Reference	Comments
Desert Rock Power Project (NM)	0.010	lb/MMBtu	Fabric filter	Permit application	
Southern Illinois Clean Energy Center/Steelhead Energy LLC (IL)	0.0092	lb/MMBtu	Syngas cleanup with hybrid dry filter	Southern Illinois October 2004 BACT analysis (b)	Permit limit is filterable only.
Elm Road Generating Station (WI)	0.011	lb/MMBtu		January 14, 2004 Wisconsin air permit (c)	PM10 lb/MMBtu is based on gas turbine heat input.
Kentucky Pioneer Power (KY)	0.011	lb/MMBtu		Southern Illinois October 2004 BACT analysis (b)	
Lima Energy (OH)	0.010	lb/MMBtu		Southern Illinois October 2004 BACT analysis (b)	
Mesaba Energy Project	0.010	lb/MMBtu		Excelsior energy Presentation(d)	

(a) Some IGCC emission rates may be based on heat input to the gas turbine. Emission rates based on coal feed might be 10% to 30% higher.

(b) Southern Illinois Clean Energy Center Air Permit Application, Appendix E, Best Available Control Technology Analysis. October 2004.

(c) Elm Road Generating Station Air Pollution Control Construction Permit 4530-1, Wisconsin DNR, January 14, 2004.

(d) Why IGCC? The Mesaba Energy Project. Energy, Innovation, and Economic Development, Minneapolis, MN, June 21, 2005.

Table 4 Proposed Desert Rock VOC Emission Comparison to a Recent Proposed IGCC Plant

Project	Emission Rate (a)		Emission Control Method	Reference	Comments
Desert Rock Power Project (NM)	0.0030	lb/MMBtu	Good Combustion	Permit application	
Southern Illinois Clean Energy Center/Steelhead Energy LLC (IL)	0.0029	lb/MMBtu	Good Combustion	Southern Illinois October 2004 BACT analysis [(b)]	
Elm Road Generating Station (WI)	0.0017	lb/MMBtu	Good Combustion	January 14, 2004 Wisconsin air permit [(c)]	VOC lb/MMBtu is based on gas turbine heat input.
Kentucky Pioneer Power (KY)	0.0044	lb/MMBtu	Good Combustion	Southern Illinois October 2004 BACT analysis [(b)]	
Lima Energy (OH)	0.0082	lb/MMBtu	Good Combustion	Southern Illinois October 2004 BACT analysis [(b)]	
Mesaba Energy Project	0.0020	lb/MMBtu	Good Combustion	Excelsior energy Presentation[(d)]	In a June 15, 2005 presentation Conoco Phillips (the technology supplier) indicated that emissions would be 0.030 lb/MMBtu.[(e)]

(a) Some IGCC emission rates may be based on heat input to the gas turbine. Emission rates based on coal feed might be 10% to 30% higher.

(b) Southern Illinois Clean Energy Center Air Permit Application, Appendix E, Best Available Control Technology Analysis. October 2004.

(c) Elm Road Generating Station Air Pollution Control Construction Permit 4530-1, Wisconsin DNR, January 14, 2004.

(d) Why IGCC? The Mesaba Energy Project. Energy, Innovation, and Economic Development, Minneapolis, MN, June 21, 2005.

(e) E gas technology for Coal Gasification. Indiana Utility Regulatory Commission, June 15, 2005 presentation by Conoco Phillips

Table 5 Proposed Desert Rock CO Emission Comparison to a Recent Proposed IGCC Plant

Project	Emission Rate (a)		Emission Control Method	Reference	Comments
Desert Rock Power Project (NM)	0.1000	lb/MMBtu	Good Combustion	Permit application	
Southern Illinois Clean Energy Center/Steelhead Energy LLC (IL)	0.0400	lb/MMBtu	Good Combustion	Southern Illinois October 2004 BACT analysis [b]	
Elm Road Generating Station (WI)	0.0300	lb/MMBtu	Good Combustion	January 14, 2004 Wisconsin air permit [c]	CO lb/MMBtu is based on gas turbine heat input.
Kentucky Pioneer Power (KY)	0.0440	lb/MMBtu	Good Combustion	Southern Illinois October 2004 BACT analysis [b]	
Lima Energy (OH)	0.1370	lb/MMBtu	Good Combustion	Southern Illinois October 2004 BACT analysis [b]	
Mesaba Energy Project	0.0300	lb/MMBtu	Good Combustion	Excelsior energy Presentation[d]	In a June 15, 2005 presentation Conoco Phillips (the technology supplier) indicated that emissions would be 0.066 lb/MMBtu.[e]

(a) Some IGCC emission rates may be based on heat input to the gas turbine. Emission rates based on coal feed might be 10% to 30% higher.

(b) Southern Illinois Clean Energy Center Air Permit Application, Appendix E, Best Available Control Technology Analysis. October 2004.

(c) ELM Road Generating Station Air Pollution Control Construction Permit 4530-1, Wisconsin DNR, January 14, 2004.

(d) Why IGCC? The Mesaba Energy Project. Energy, Innovation, and Economic Development, Minneapolis, MN, June 21, 2005.

(e) E gas technology for Coal Gasification. Indiana Utility Regulatory Commission, June 15, 2005 presentation by Conoco Phillips

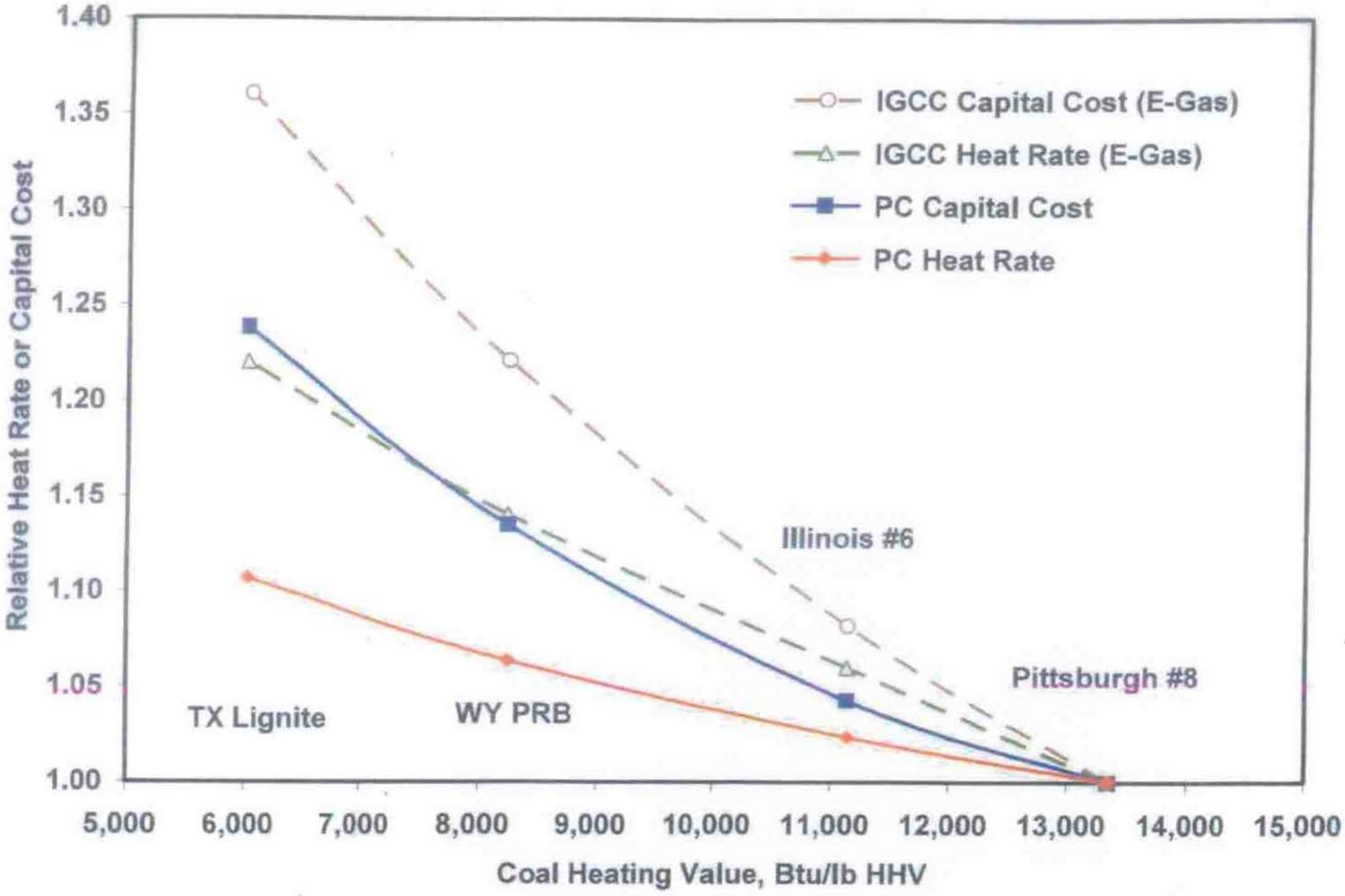
Table 6 Proposed Desert Rock Emission Comparison to a New CFB Plant

Parameter	Desert Rock (a)	CFB	Units	Comments
Heat rate	8,792	9,950	Btu/kWh	Sub critical CFB. Super critical CFBs are under development.
SO2 emissions	0.060	0.0576	lb/MMBtu	Sevier Power October 12, 2004 permit limits SO2 emissions to 0.05 lb/MMBtu as a 24-hr average and 0.022 lb/MMBtu as a 30-day average.(b) Desert Rock design fuel contains 2.62 times as much S on a lb/MMBtu basis.
SO2 emissions	2,998	3,258	ton/yr	1,366 MW and 95% capacity factor
Difference		259	ton/yr	CFB emissions are higher than SCPC
NOx emissions	0.060	0.100	lb/MMBtu	Sevier Power October 12 permit.
NOx emissions	2,998	5,656	ton/yr	1,366 MW and 95% capacity factor
Difference		2,657	ton/yr	CFB emissions are much higher than SCPC
PM10 emissions	0.010	0.010	lb/MMBtu	Filterable PM10 only. Definitive information on condensable PM10 emissions is not available. Filterable PM emissions using a bag house will be similar for both combustion technologies.
PM10 emissions	500	566	ton/yr	1,366 MW and 95% capacity factor
Difference		66	ton/yr	CFB emissions are higher than SCPC
VOC emissions	0.0030	0.0050	lb/MMBtu	Sevier Power BACT analysis.
VOC emissions	150	283	ton/yr	1,366 MW and 95% capacity factor
Difference		133	ton/yr	CFB emissions are higher than SCPC
CO emissions	0.10	0.10	lb/MMBtu	Sevier Power October 12 permit limit is 0.115 lb/MMBtu. CFB permit limits are in the 0.1 to 0.15 lb/MMBtu range with most limits set at 0.15 lb/MMBtu.
CO emissions	4,997	5,656	ton/yr	1,366 MW and 95% capacity factor
Difference		658	ton/yr	CFB emissions are lower than SCPC
Sulfuric acid mist emissions	0.0040	0.0063	lb/MMBtu	Sevier Power October 12, 2004 permit limits H2SO4 emissions to 0.0024 lb/MMBtu as a 24-hr average. Desert Rock design fuel contains 2.62 times as much S on a lb/MMBtu basis.
Sulfuric acid mist emissions	200	356	ton/yr	1,366 MW and 95% capacity factor
Difference		156	ton/yr	CFB emissions are higher than SCPC
Mercury emissions	9.28E-06	1.03E-05	lb/MWh	Desert Rock is based on average mercury concentration in coal of 0.046 ppm and 80% control. Mercury emissions are not known to be affected by the combustion technology. CFB emission rate is higher due to higher heat rate.
Mercury emissions	103	117	lb/yr	1,366 MW and 95% capacity factor
Difference		14	lb/yr	CFB emissions are higher than SCPC

(a) The Desert Rock SCPC annual potential to emit presented in the PSD permit application is based on the a probable worst case one hour operating condition. The power output and heat rate in this table is based on a annual average operating condition. Therefore, the annual potential to emit in the PSD permit application is approximately 10% higher.

(b) Approval Order: Sevier Power Company's 270 MW Coal-Fired Power Plant. DAQE-AN2529001-04. State of Utah Department of Environmental Quality. October 12, 2004.

Figure 1 Effect of Coal Quality on PC and IGCC Plant Heat Rates and Capital Cost



(Source: Booras, G. and N. Holt, Pulverized Coal and IGCC Plant Cost and Performance Estimates. Presented at Gasification Technologies 2004, Washington, DC., October 3-6, 2004)