Desert Rock Energy Co., PSD Appeal 08-03
Conservation Petitioners' Exhibits

EXHIBIT 28

DECLARATION OF JOHN THOMPSON

I, John Thompson, do hereby attest as follows:

1. My name is John Thompson. I am the Director of the Coal Transition Project for the Clean Air Task Force. My business address is 231 W. Main, Suite 1E, Carbondale, IL 62901. I have a B.S. in Chemical Engineering from the University of Illinois, and a Masters of Business Administration from the Olin School of Business at Washington University, St. Louis. My employer, the Clean Air Task Force (CATF), is a national nonprofit environmental organization dedicated to restoring clean air through scientific research, public education, and legal advocacy. CATF is comprised of approximately twenty professionals with backgrounds in science, engineering, law, economics and public outreach headquartered in Boston and operates with a national focus on clean air issues. CATF is a leading environmental organization addressing air quality and atmospheric protection issues, and its work is widely respected in government and industry.

2. My work for CATF addresses several areas, including: preparing comments on coal-fueled power plant air permits, evaluating the economics and environmental characteristics of advanced coal technologies such as Integrated Gasification Combined Cycle (IGCC), educating the public about health impacts of power plant pollution, and working to develop state and federal rules on power plant emissions.

3. I frequently address conferences and workshops on the topic of IGCC. In October 2003, I made a presentation at the U.S. Department of Energy's Twentieth Annual International Pittsburg Coal Conference, on the topic of "IGCC as LAER/BACT for the Production of Electricity from Coal." In April 2004, I made a presentation on IGCC environmental characteristics and economics to the Western Governors' Association Energy Summit. In June 2004, I addressed the Workshop on Gasification Technologies jointly sponsored by the U.S. Department of Energy, the National Association of Regulatory Commissioners, the Gasification Technologies Council, and the Southern States Energy Board. My presentation was titled "The BACT Analysis: Does IGCC Meet the Test?" In August 2004, I made a presentation at the USEPA's Air Innovations Conference on the topic of IGCC. In October 2004, I made a presentation to the annual meeting of STAPPA/ALAPCO, a national association of state and tribal air directors, on the topic of IGCC. My presentation was entitled "Integrated Gasification Combined Cycle (IGCC): Environmental Impacts and Policy Implications." In 2005, I addressed the Platts IGCC Symposium. My presentation was entitled "Integrated Gasification combined Cycle (IGCC) Environmental Performance." I also addressed a gasification workshop sponsored by the Gasification Technologies Council in April 2005 in Knoxville TN on IGCC. In November 2005, I spoke on IGCC and carbon sequestration topics at Infocast's IGCC Project Development and Finance Seminar and on "Public Perception of Gasification" at MIT's Carbon Sequestration Forum VI. In May 2006, I addressed Platts 2nd Annual IGCC Symposium on the topic of gasification performance.

4. I have visited gasification plants in the United States and Europe, including the Polk IGCC plant in Florida, the Wabash IGCC plant in Indiana, the Dakota Gasification Plant in North Dakota which processes lignite into methane, Eastman Chemical's coal

gasification plant in Kingsport Tennessee, Nuon's IGCC plant in the Netherlands, and both Future Energy and BGL's gasifiers at Schwartze Pumpe in Germany.

5. In my work with CATF, I have prepared and submitted comments on draft air permits to state regulators, focusing on the need to properly evaluate IGCC as an alternative to conventional coal-fired power plants. I have also testified as an expert witness on air permit appeals in Montana, Texas, and Wisconsin on the topic of IGCC. I have also testified at a Colorado Public Utilities Commission proceeding also on the topic of IGCC.

6. I was also co-chair the Technologies Subcommittee of the Western Governors Association's Clean Coal Task Force, where I reviewed the cost and performance of numerous current and future coal technologies. This review included IGCC technology. I also served as a member of Clean Coal Study Group in Wisconsin. This initiative was created as part of Wisconsin Governor Jim Doyle's Conserve Wisconsin initiative. The Wisconsin Public Service Commission and the Department of Natural Resources convened the group. The charge was to develop a report on the feasibility of IGCC technology for Wisconsin.

7. Prior to joining the Task Force, I was Director of Clean Air Programs at the Illinois Environmental Council. For thirteen years, I was Executive Director of the Central States Education Center in Champaign, Illinois, an organization that developed advocacy and technical assistance programs on solid and hazardous waste issues. I began my career as a process development engineer with the Procter & Gamble Company.

8. Thompson Attachment 1 is my resume that describes my professional experience.

Purpose and Methodology

9. In this declaration, I assess IGCC as an option for Best Available Control Technology for the Desert Rock location. My methodology for this evaluation involved several steps, including:

- I reviewed the Docket Index of the Administrative Record for Desert Rock Energy Facility, PSD Permit No. NSR 4-1-3, AZP 04-01 to determine what reports and other information served as the basis for the permit record.
- I reviewed documents relevant to BACT and IGCC determination in the record. Specifically, I reviewed the PSD application dated May 2004, Desert Rock Energy Center (AZP 04-01) Proposed Permit Conditions, Ambient Air Quality Report (NSR 4-1-3, AZP 04-01), Integrated Gasification Combined Cycle Compared to the Desert Rock Energy Project (Docket Index I-D), Desert Rock Energy Project design comparison to Integrated Gasification Combined Cycle and circulating Fluidized Bed Combustion (Docket Index I-E). I had previously reviewed other IGCC related documents in the record, including Docket Index VII-C, VII-F, and VII-H.
- I reviewed other documents for my analyses. These included USEPA's New Source Review Workshop Manual (Draft Oct 1990), and as described in more detail later in this declaration, recently filed applications for IGCC air permits in

the United States and other IGCC and gasification reports.

• I analyzed these documents and based upon my education and professional experience, conducted the calculations, analyses, and formed the opinions and conclusions found in this declaration.

Context for Determining BACT

10. Typically, the applicant for a proposed power plant prepares an analysis for each pollutant subject to BACT that is reviewed by the permitting authority. The evaluation is conducted on a case-by-case basis. Most frequently, the analysis follows what is called a "Top-Down" process. In the first step of a top-down BACT analysis, the applicant identifies all of the available technologies. USEPA defines the scope of options very broadly. It is intended to be a full-range review. For example, USEPA's New Source Review Manual describes air pollution control technologies and techniques as including "the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States."[1]

11. The second step of the BACT analysis eliminates technically infeasible options. The third step ranks the remaining options on the basis of control effectiveness with the most stringent option ranked at the top. The information in the analysis includes control efficiencies, expected emission rate, expected emissions reduction, economic impacts (cost effectiveness), environmental impacts (including impacts on water or solid waste) and energy impacts. If the applicant selects the top option, the economic analysis is not necessary, but other impacts must be described. In the fourth step, the applicant evaluates the most effective controls and documents the results. The NSR Manual describes this step as follows: "If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT."[2]

12. Recent BACT analysis for coal plants have compared different technologies such as pulverized coal, IGCC and circulating fluidized bed plants to one another. One of the best examples in my opinion is the application filed in Kentucky by the ERORA group at Cash Creek. Initially, the company filed an air application with Kentucky for a 1000 MWe PC plant. The state requested that the applicant evaluate other technologies.

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[1] NSR Manual at page B-5

[2] NSR Manual page B-9

In part because of this evaluation, ERORA switched to IGCC technology.

13. Thompson Attachment 2 is the revised BACT analysis filed by ERORA in the May of 2006 at Cash Creek. It identifies all the options available to generate electricity from coal, including pulverized coal combustion, circulating fluidized bed, and IGCC. Next, the application evaluated the technical feasibility of all three options and concluded that they were all available at the Henderson County Kentucky site. The analysis ranked the three options based upon emission rates. IGCC emerges as the top-ranked technology based upon the emission analysis. In the fourth step, the applicant considered collateral impacts of the emission technology choices, and finally, in step 5, selected the following emission rates as BACT for the Cash Creek site that were based upon IGCC technology[3]:

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are needed to see this picture.

IGCC Technology Described

[3] See Thompson Attachment 2 at page4-63.

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

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

16. After leaving the gasifier, the syngas undergoes several clean-up operations. Particulate matter is removed. Next, a carbon bed can be used to take out mercury. Finally, sulfur (in the form of H_2S) is removed from the syngas in a combination of steps that usually involve hydrolysis followed by an adsorption operation using MDEA (methyldiethanolamine) or Selexol. The H_2S that is removed from the syngas is usually converted into elemental commercial-grade sulfur using a Clauss plant.

17. The clean syngas enters a combustion turbine where it is burned to produce electricity. The heat from the exhaust gases is captured in a heat recovery steam generator (HRSG) and the resulting steam is used to produce more electricity. The combustion turbine, combined with the HRSG, is the same configuration commonly used for natural gas combined cycle (NGCC) plants. In Europe and Japan, some IGCC units have installed selective catalytic reduction (SCR) to control nitrogenous oxide (NOx) emissions from the turbine, but in the United States, NOx emissions at existing IGCC plants have been reduced with diluent injection only.

<u>IGCC Operating and Proposed Plants</u>

18. Gasification dates back to the 18th century, when "town gas" was produced using fairly simple coal-based gasification plants. But what we think of as modern gasification technology dates back to the 1930's when gasification was developed for chemical and fuel production. Today, there are around 130 gasification plants worldwide that produce fertilizers, fuels, steam, hydrogen and other chemicals, and electricity. Of these 130 plants, fourteen are IGCC plants. Together, these plants have a capacity of 3,632 megawatts (MW) electricity, and are worth nearly $8 billion. These plants use a variety of fuels such as oil residues, petroleum coke and coal. The first commercial-scale demonstration IGCC plant in the United States was Southern California Edison's Cool Water located at Barstow, California. It operated between 1984 and 1989. The plant successfully utilized a variety of coals, both subbituminous and bituminous, coals and had a feed of about 1,200 tons/day. The project used an oxygen-blown Texaco gasifier with full heat recovery using both radiant and convective syngas coolers

19. Four IGCC plants tend to be the focus of utility interest because they were designed to use coal: 1) Wabash, Indiana, 2) Polk, Florida, 3) Nuon, Netherlands, and 4) Elcogas, Spain.

> Wabash, Indiana: Wabash River Coal Gasification Repowering Project in Indiana began operation in November 1995. It demonstrated the repowering of an existing coal plant to IGCC. The plant uses an "E-Gas" which is now sold by ConocoPhillips.
>
> Polk, Florida: The Tampa Electric Polk Power Station began operation in 1996. It produces 250 MW (net) of electricity. It uses a Texaco (now GE) oxygen-blown gasification system. Power comes from a GE 107FA combined cycle system. During the summer peak power months, availability is greater than 90 percent when using back-up fuel.
>
> Nuon, Netherlands: The Nuon plant in Buggenum, the Netherlands began operation in 1994. It is a 253 MW oxygen-blown Shell IGCC plant with a nominal output of 253 MWe. It uses a Siemens V94.2 combined cycle turbine. Unlike the U.S. plants, the Nuon facility is "fully integrated" meaning that the air for the air separation unit is extracted from the gas turbine compressor. The plant has utilized a wide variety of coals. In 2002-2003, it operated in load following mode, but is in baseload operation in 2004.
>
> Elcogas, Spain: The Elcogas facility in Puertollano Spain is a 298 MWe gasification system that uses a Prenflow gasifier and Siemens V94.3 turbine. It went into operation in 1998. Like Nuon, it is a fully integrated IGCC plant.

20. A second set of plants built after Wabash, Polk, Nuon, and Elcogas are also important in the progression of IGCC. These plants operate at refineries in Italy. They are: Sarlux 545 MW, Sardinia; ISAB Energy 512 MW, Sicily; and Api Energia 280 MW, Falconara. The first two demonstrate that IGCC plants can be built at a scale above 500 MW. All three plants were built using non-recourse project financing provided by over 60 banks and other lending institutions. They show that IGCC can be a commercially bankable technology. Both the Salux and ISAB Energy plants use more than one gasification "train" and operate with more than 90 percent availability. The Italian experience with IGCC, while using oil as a fuel, is relevant to discussions of coal-fired or coke-fired IGCC, because essentially the same equipment is utilized in both instances, differing only in the feed preparation and how solids are removed.

21. In the United States, a large number of coal-based IGCC and gasification projects are under development. These include:

- Two 629 MWe IGCC plant to be built by the nation's largest utility, American Electric Power Company (AEP), in Ohio and West Virginia scheduled to be operational in 2010;
- 600 MWe IGCC plant proposed by the nation's fourth largest utility, Cinergy (now part of Duke), near Edwardsport, Indiana;
- 630 MW IGCC plant proposed by Tondu in Texas;
- 630 MW IGCC plant proposed by Energy Northwest in Washington

- 366 MW IGCC plant proposed by Summit in Oregon,
- Three repowering projects to take old PC plants and convert them to IGCC by NRG in CT, DE, and NY. Each would be 630 MW
- Two 630 MW IGCC plants proposed by the ERORA Group (one in Illinois and one in Kentucky) and
- Two 606 MWe IGCC in Hoyt Lake Minnesota by Excelsior Energy

22. The figure below illustrates the range and locations of gasification projects across the United States[4]. In some Midwestern state

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are needed to see this picture.

s, IGCC and other gasification plants now comprise more than half the new coal plant proposals.

23. The range of IGCC projects under development in the United States includes proposals that would be fueled with petroleum coke, bituminous coal, subbituminous coal, and lignite. For example, the Department of Energy Announced in August 2006 that it had received tax credit applications under the Energy Policy Act of 2005 from 18 IGCC projects-- 10 using bituminous coal, six using subbituminous coal, and two that

[4] Phil Amick, "Experience with Gasification of Low-Rank Coals," presented at Workshop on Gasification Technologies, Bismark North Dakota, June 28, 2006.

would use lignite[5].

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

25. Based upon the wide number of IGCC projects proposed and operating both in the United States and worldwide, my knowledge of the IGCC systems offered by major companies and how they perform, I conclude that IGCC is an available technology and must be considered in the first step of a BACT analysis for a coal-fueled power plant.

Technical Feasibility of IGCC at the Desert Rock Location

26. The second step of the BACT analysis eliminates options based upon physical, chemical, and engineering principles that would preclude the successful use of the control option. Relevant issues for consideration of IGCC in this step at the Desert Rock Location include, the design fuel, water use, the availability of the plant (once built) to be dispatched, plant size, altitude and financing.

27. The design fuel for the DREF is a low-rank coal with a heat content of 8,953 Btu/lb poses no technical barrier for using IGCC. Thompson Attachment 3 is a presentation entitled *E-Gas Applications for Sub-Bituminous Coal*, a paper presented by the vendor ConocoPhillips at the Oct 11, 2005 Gasification Technologies Council. The paper concludes that 37% of the coal that has been gasified in the United States for power generation purposes has been subbituminous coal. Based upon my understanding and knowledge of the different gasification technologies offered by major vendors, subbituminous coal of the type to be used at DREF could be gasified in Shell, Siemens or ConocoPhillips gasifiers. Based upon these factors, I conclude that the design fuel to be used at the DREF poses no feasibility issues for an IGCC plant.

28. An IGCC plant uses approximately one-half to two-third less water than a pulverized coal plant.[6] Therefore, water use poses no barrier for IGCC deployment at the DREF site.

29. Availability is a measure of the time a plant is capable of producing electricity. Availability excludes time when a plant is not capable of producing electricity because of planned or unplanned outages. IGCC plants built in the early 1990s such as Polk and Wabash that operate without a spare gasifier have demonstrated availabilities of 85%. Thompson Attachment 4 is a recent Gas Turbine World article that

[5] DOE, Fossil Energy Techline, issued August 14, 2006, "Tax Credit Programs Promote Coal-Based Power Generation Technologies."

[6] Major Environmental Aspects of Gasification-Based Power Generation Technologies, U.S. DOE/NETL, December 2002 at page 2-61.

reports that the capacity factors of the more recently built IGCC plants in Italy that utilize refinery waste as a fuel. As the report notes, the availability of these plants are between 90% and 94%. Major vendors of IGCC plants such as GE, Shell and ConocoPhillips will warrant that new IGCC plants will achieve greater than 90% availability with a spare gasifier. Therefore, I conclude that plant availability poses no technical barriers for an IGCC plant at the DREF site.

30. The DREF plant size consists of two 750 MW (gross) boilers that would produce 1336 MW of net power. IGCC plants are built in trains that are sized to the turbine. Typically, this means that an IGCC plant is built in modules ranging in size from 250 MW to 315 MW. The Wabash, Polk, ELCOGAS, and NUON plants are all single train modules that are roughly 250 MW to 270 MW. Existing IGCC plants in refineries in Italy are 500 –600 MW that consist of two modules. Proposed IGCC plants in the United States consist of several trains to achieve sizes ranging from 630 MW to 1212 MW. Fore example, the ERORA IGCC plants in Illinois and Kentucky would use two trains to achieve 630 MW. The Mesaba One and Mesaba Two plants would use multiple modules in two phases to build a 1212 MW subbituminous coal IGCC facility. Proposed IGCC plants in Europe (Nuon's Magnum) will be 1200 MW. The modular nature of IGCC plants allows the technology to be readily scalable. Therefore, I conclude that the plant size of the proposed DREF does not pose a feasibility issue for IGCC.

31. Altitude does not present a significant barrier to IGCC development. As co-chair of the Technologies Subcommittee of the Western Governors Association's Clean Coal Task Force, I reviewed issues associated with the costs of altitude impacts on Air Separation Units and turbines. The draft report, which was released for public comment by the Western Governors' Association Clean Coal Task Force states, "Altitude and Ambient Temperature effects on IGCC units are real, but are manageable at reasonable cost and efficiency impacts using state-of-the art methods that have been demonstrated at commercial scale." Thompson Attachment 5 is a summary of the altitude impacts on IGCC that the Technologies Subcommittee developed on the issue.

32. Although not a physical, chemical or engineering principle, Sithe raises issues of financing costs of IGCC on page 2-2 of the September 2005 report entitled "Desert Rock Energy Project Design comparison to Integrated Gasification Combined Cycle and Circulating Fluidized Bed Combustion." For convenience, I address these issues under the topic of feasibility, rather than as a cost issue that should be addressed later in the BACT analysis. In my opinion, IGCC plants can obtain commercially financing at acceptable terms. The Italian IGCC plants and recent US IGCC plants were underwritten with non-recourse financing and bonds. Thompson Attachment 3 is a recent Gas Turbine World article that details the financing of recent IGCC projects (page 36). Recently, IGCC plants in the United States have announced equity investors. These include ERORA's Taylorville IGCC project that announced in the Summer of 2006 that Tensaka, an Omaha based IPP, had invested in their project, and in October 2006, ERORA announced that the D. E. Shaw Group had committed up to $500 million to build the Cash Creek IGCC plant in Kentucky.

33. Based upon my review of the design fuel, water use, availability to dispatch an IGCC plant, plant size, altitude issues, and financing issues, I conclude that IGCC cannot be eliminated for technical feasibility reasons in the BACT review.

Ranking Environmental Performance

34. The third step of the BACT analysis ranks the remaining options on the basis of control effectiveness with the most stringent option ranked at the top. To assess, control effectiveness, I reviewed the IGCC reports in the Administrative Record and compiled the BACT analysis for recently filed IGCC air permits in the United States. For the most part, these IGCC air permit applications are not contained in the Administrative Record for the DREF application.

35. The BACT analysis from recently filed air permit applications that I reviewed included:

- AEP in Ohio (application filed Oct 2006)
- AEP in W Virginia (application filed Oct 2006)
- Northwest Energy in Washington (application filed September 2006)
- Tondu in Texas (application filed September 2006)
- Duke in Indiana (application filed August 2006)
- ERORA in Kentucky (revised application filed June 2006)
- ERORA in Illinois (revised application filed March 2006)
- Mesaba One and Mesaba Two in Minnesota (application filed Summer 2006)
- Steelhead Energy in Illinois (Application filed Fall 2004)

The AEP (Ohio and West Virginia), Northwest Energy, Tondu, Duke, Mesaba, and ERORA Taylorville, are shown as Thompson Attachments 6 through 12.

36. I also reviewed issued permits for IGCC plants including Global Energy, Kentucky Pioneer, and WEPower.

37. I also reviewed the emission and environmental performance of existing plants such as Wabash, Polk, Nuon, Elcogas, Negishi (a Japanese IGCC plant at a refinery. Negishi employs an SCR).

38. I also reviewed the July 2006 USEPA report, "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies."

39. I prepared the table below, entitled "Summary of Recent IGCC Permits and Proposed Permit Levels", that summarizes proposed emission levels from IGCC plants that have recently received or applied for air permits. The majority of IGCC plants proposed in the last 12 months have sought to control sulfur using Selexol, a more effective control strategy than MDEA. These plants include, AEP in Ohio and West Virginia, Northwest Energy, Tondu, Duke, ERORA (Illinois and Kentucky). Only one air permit application filed in the last 12 months, Mesaba (filed June 2006) uses the less effective MDEA. Selexol effectively removes sulfur levels to between .00117 to .0019 lb/MMBtu heat input into the gasifier.

Summary of Recent IGCC Permits and Proposed Permit Level

	Approved Permit			Application Filed, Draft Permit Not Issued Yet								
Pollutant	Global Energy Lima, Oh, 590 MW	Kentucky Pioneer Energy, KY	Wisconsin Electric Elm Road, 600 MW	ERORA Cash Creek, KY, 630 MW	Southern Illinois Clean Energy Complex, IL, 640 MW & 110 MMSCF methane	ERORA, Taylorville, IL 630 MW	Nueces, TX, 600 MW	Energy Northwest, WA, 600 MW	AEP, OH, 629 MW	AEP, WV, 629 MW	Mesaba One (606 MW), Mesaba Two (606), MN,Total 1,212 MW	Duke, Edwardsport, IN, 630 MW
	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(in lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)
SO2	0.021	0.032 -3 hr ave	0.03 -24 hr ave	0.0117 -3 hr ave	0.033 -30 day ave	0.0117 -3 hr ave	0.019	0.016 -3 hr ave	0.017	0.017	0.025	Repower, net from BACT
NOx	0.097	0.0735 -3 hr ave	0.07 (15 ppmdv) -30 day ave	0.0246-24 hr ave	0.059 -30 day ave	0.0246 -24 hr ave	0.019	0.012 -3 hr ave	0.057	0.057	0.057	Repower, net from BACT
Mercury			.56 x 10-6	.197 x10-6 (1)	.547 X10-6	.19 x 10-6 (1)	1.825 x10-6	1.1 x10-5			90% removal, .026 tons Phase I and II total	.008 tons/yr
PM	0.01	.0.011	0.011 (backhalf)				0.015	0.001			0.009	18.1 lbs/hr
PM10			0.011 (backhalf)	0.0063 -3 hr ave (filterable)	0.00924 (filterable)	0.0063 -3 hr ave (filterable)	0.014		.006 (filterable)	.006 (filterable)		
VOCs	0.0082	0.0044	(LAER) (3)	0.006 -24 hr ave	0.0029	0.006 -24 hr ave	0.004	0.003	0.001	0.001	0.0032	1.4 ppmvw
Sulfuric Acid Mist			0.0005 -3 hr ave	0.0026 -3 hr ave	0.0042 -30 day ave	0.0026 -3hr ave	0.0001		98 tons/yr	98 tons/yr		
Fluorides (2)												
CO	0.137	0.032 -3 hr ave	.030 -24 hr ave	0.036 -24 hr ave	0.04 -30 day ave	0.036 -24 hr ave	0.04	0.036	0.031	0.031	0.0345	15 ppmvd
Lead			0.0000257									
Sulfur Control Technology	MDEA	MDEA	MDEA	Selexol	MDEA	Selexol	Selexol	Selexol	Selexol	Selexol	MDEA	Selexol
Nox Control Technology	Diluent injection	Diluent injection	Diluent injection	Diluent/SCR	Diluent injection	Diluent/SCR	Diluent/SCR	Diluent/SCR	Diluent injection	Diluent injection	Diluent injection	Diluent/SCR

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

40. As the table "Summary of Recent IGCC Permits and Proposed Permit Levels" shows, a narrow majority of IGCC plants that have filed applications in the last 12 months include SCRs to control NOx. These include, Northwest Energy, Tondu, ERORA in Illinois and Kentucky, and Duke in Indiana (The Duke plant includes and SCR, but bases reductions on diluent injection only). The NOx emission rates for SCR controlled IGCC plants is .012 - .025 lb/MMBtu based upon heat into the gasifier.

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

42. In deciding which emission rates to compare to the DREF application rates, I placed the highest weight on recently proposed IGCC plants because they represent the most current view of IGCC permit levels. I placed weight on the EPA report, but recognized, as described above, that it is somewhat out of date. Finally, I placed the least weight on existing IGCC plants and IGCC plants with permits issued prior to 2003 because they don't represent the capabilities of current IGCC technology.

43. I prepared the table below, entitled "Emission Rates of Proposed DREF Permit Compared to IGCC Requested Rates," that summarizes the range of recently filed air permit for IGCC plants (filed in the last 12 months plus the most recently issued air permit for We Energies in Wisconsin) and compares them to the proposed DREF permit.

Emission Rates of Proposed DREF Permit Compared to IGCC Requested Rates

	DREF	IGCC			
	Proposed Emission Rates[a]	Sulfur control using MDEA	Sulfur control using Selexol	Nitrogen control using diluent injection	Nitrogen control using both diluent injection and SCR
	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)	(lb/MMBtu)
SO2	0.06	.025-.033	.0117-.019		
NOx	0.06			.057-.07	.012-.025
PM (filterable)	0.010		0.0063-0.014		
PM10 (total)	0.020				
CO	0.10		0.03-0.04		
Sulfuric Acid Mist	0.0040		0.0005-0.0042		
VOC	0.0030		0.001-0.006		
Hg	No limit		0.00000019-0.00000056		

[a]All proposed DREF emission rates listed would apply on a 24-hour average basis with the exception of the limit for sulfuric acid mist which would apply on a 3-hour average basis.

44. I conclude that an IGGC plant at the Desert Rock location would have significantly lower emissions than the supercritical PC plant proposed by Sithe.

45. Based upon my review, an IGCC plant would have an SO2 removal rates corresponding to over 99.2% with Selexol and around 98% -99% with MDEA. The DREF removal rate, in contrast, is only about 96.8%.

46. An IGCC plant would be expected to emit about 1/3 as much sulfur dioxide as the DREF proposal. I conclude based upon my knowledge of IGCC plant design, operation, and emissions, that IGCC is an inherently lower emitting process for conversion of coal to electricity with respect to sulfur dioxide.

47. An IGCC plant would be expected to emit about 1/3 as much nitrogen oxide as the DREF proposal because SCR would likely be included in an IGCC design.

48. An IGCC plant would be expected to emit about 40% less PM, two-thirds less CO, and significantly less sulfuric acid mist and VOCs. I conclude based upon my knowledge of IGCC plant design, operation, and emissions, that IGCC is an inherently lower emitting process for conversion of coal to electricity with respect to these pollutants.

49. In my opinion, Sithe incorrectly estimates the emissions of an IGCC plant by

assuming that the likely control devices would involve MDEA and diluent injection,

50. Based upon the factors cited above, I conclude that IGCC is the top ranked control technology for the DREF location.

Evaluation of the Most Effective Controls

51. In the fourth step of the BACT analysis, the applicant evaluates the most effective controls and documents the results. In conducting this step, I considered energy, environmental, and economic impacts.

Energy Effects

52. The efficiency of a power plant, and therefore its energy use, is measured by its heat rate. In October 2005, ConocoPhillips presented a paper at the Gasification Technologies Council Conference entitled, "E-Gas Applications for Sub-bituminous Coal." The report (Thompson Attachment 3) describes the design, environmental performance and costs for a 555 MW (net) IGCC plant at an altitude and coal heat content comparable to Desert Rock. Sithe also assumed ConocoPhillips gasifiers in its September 2005 report to Region 9. The table below compares Sithe's estimate of IGCC design at Desert Rock to design in the ConocoPhillips presentation (scaled to the same size and including spare):

	Design Presented by Sithe (1)	Design based on CP Presentation (2)	Design based on CP Presentation (2)
Spare	With spare	No Spare	With Spare
Net Power (MW)	1366	1387	1387
Net Heat rate (HHV)	9775	9075	9075
altitude	5415 MSL	5000 MSL	5000 MSL
coal heat content (Btu/lb)	8953	8340	8340
Number of gasifiers	12	10	12
Number of Turbines	7 GE7FA	5 SGT6-5000F	5 SGT6-5000F
Number of Air Separation Units	6	not specified	not specified
Pollution controls	not specified	Selexol/SCR	Selxol/SCR

Notes
1. "Desert Rock Energy Project Design Comparison to Integrated Gasification Combined Cycle and Circulating Fluidized Bed Combustion," ENSR Corporation, September 2005, at 4-9.
2. "E-Gas Applications on Sub-bituminous Coals," Presentation by ConocoPhillips, October 2005.

53. As the table above shows, the Sithe report significantly overstates the heat

rate and the number of turbines needed for an IGCC plant at the Desert Rock site.

54. USEPA estimates the heat rate of an IGCC plant to be even lower on subbituminous coals. In its report, "Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies," USEPA estimates the heat rate of a supercritical PC as 9,000 Btu/kWh and an IGCC as 8,520 Btu/kWh.[7]

55. Based upon my experience and the information cited above, I conclude that the Sithe's conclusion that an IGCC plant is significantly less efficient than a supercritical pulverized coal plant is wrong. I conclude that an IGCC is either more efficient or equivalent to a supercritical PC plant at the Desert Rock location using coal with a heat content of 8,900 Btu/lb. Therefore, the use of IGCC technology does not pose any collateral energy issues for the purposes of the fourth step of a BACT analysis.

Environmental Issues- Greenhouse Gases

56. As described earlier in this declaration, IGCC plants are typically more efficient or at least as efficient as measured by heat rate compared to a PC unit. This means that CO_2 emissions -- the primary greenhouse gas responsible for anthropogenic contributions to global warming -- are generally lower for an IGCC plant compared to a PC unit.

57. Furthermore, IGCC has an option to make even deeper cuts in carbon dioxide. Conventional coal plants lack commercially available technology to make significant CO2 reductions. The technology to remove CO2 from syngas (Selexol or Rectisol) has been in commercial use for decades in plants that gasify coal to make ammonia. The CO2 from these ammonia plants is often used to make urea. IGCC technology can accommodate 90%-100% CO2 removal by employing a "water shift" of the syngas to convert CO in the syngas to H2 and CO2. The Selexol or Rectisol unit can separate the CO2 for compression and sequestration, and the remaining hydrogen in the syngas can be burned in a turbine to produce electricity.

58. In documents filed with Minnesota Public Service Commission, the developers of the proposed Mesaba IGCC plant outlined a conceptual plan that if implemented, could capture about 30% of the CO2 from an IGCC plant at reduced cost relative to full carbon capture[8]. The plan takes advantage of the fact that syngas produced with subbituminous coal (the type proposed at DREF) has relatively more CO2 in the syngas than syngas made with bituminous coal. The Mesaba conceptual plan would not involve a water shift, nor would it involve Selexol or Rectisol, nor would it involve extensive turbine modifications. An amine scrubber would follow the MDEA sulfur control step prior to syngas combustion in the turbine.

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[7] USEPA, Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, July 2006, at page ES-7.

[8] "Plan for Carbon Capture and Sequestration," Mesaba Energy Project, Excelsior Energy, dated Oct 10, 2006.

59. In contrast, pulverized coal plants do not have commercially available technology to capture CO_2 from the flue gas. When this technology does become commercially available, studies suggest if will be much more expensive to retrofit to pulverized coal plants than IGCC plants. For example, in his Master's Thesis at MIT, Mark Bohm studies CO_2 "lock-in" that can occurs when a new coal plant is built and CO_2 capture costs are high. His study shows, that based upon IGCC's lower carbon capture costs, that IGCC plants will have significantly lower lifetime emissions of carbon dioxide compared to PC plants under moderate carbon taxes ($10-$35/ton).[9] Similarly, studies by EPRI[10] and the Intergovernmental Panel on Climate Change[11] show IGCC having a significant cost advantage over pulverized coal when carbon dioxide is captured.

60. *Solid Wastes:* The waste leaving an IGCC plant is vitrified, thereby potentially reducing some of the solid waste disposal issues associated with coal combustion. Indeed, IGCC plants produce 30-50% less solid waste than PC plants.[12] Also, because of the better heat rate associated with IGCC, less coal would have to be mined when compared to conventional coal plants.

61. *Economic Impacts-* USEPA's New Source Review Manual describes the method for evaluating economic impacts in the Top-Down BACT analysis using the average cost effectiveness of pollutants removed and the incremental cost effectiveness of pollutants removed. The manual defines these terms as follows:

$$C_{ave} = \frac{\text{Control Option Annualized Cost}}{\text{Baseline Emission Rate} - \text{Control Option Emission Rate}}$$

Where C_{ave} = Average cost effectiveness, $ per ton of pollutant controlled

$$C_{incremental} = \frac{\text{Total Cost of Option} - \text{Total Cost of Next Control Option}}{\text{Next Control Option Emissions Rate} - \text{Control Option Emission Rate}}$$

Where, $C_{incremental}$ = Average cost effectiveness, $ per ton of pollutant controlled

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[9] "Capture-ready Power Plants- Options, Technologies and Costs, Mark Bohm, MIT, June 2006.

[10] "IGCC Technology Status, Economics and Needs," Neville Holt, presented at the International Energy Agency (IEA) Zero Emission Technologies (ZET) Technical Workshop, February 17, 2004, Gold Coast,Queensland, Australia.

[11] "Carbon Dioxide Capture and Sequestration Summary for Policymakers and Technical Summary," Intergovernmental Panel on Climate Change, October 2005, at page 9.

[12] Major Environmental Aspects of Gasification-Based Power Generation Technologies, US DOE, December 2002, Table 1-7, Page 1-27.

62. Average cost effectiveness is used in most BACT demonstrations, with some cases incremental costs being important. When a pollution control option controls more than one pollutant, the option's annual costs must be allocated among the several pollutants controlled before calculating average or incremental costs. Thompson Attachments 13 and 14 are letters from USEPA to reviewing authorities which describe the need and basis for allocating annual costs when an option controls more than one pollutant. Since IGCC technology controls more than one pollutant these cost allocation issues must be addressed when comparing IGCC with PC.

63. Sithe did not calculate both average and incremental costs. Sithe only calculated incremental cost effectiveness. By failing to calculate average cost effectiveness, Sithe failed to include a key factor in determining economic impacts.

64. Sithe failed to use the correct emission limits from IGCC technology in its calculation of incremental cost effectiveness. The table below reports the Sithe calculation and a corrected calculation that I prepared based upon the IGCC emissions described in this declaration. As the table below shows, Sithe incorrectly calculates the main pollutant benefit (as measured by tons) as a 1,726 ton per year of SO2. In fact, the total benefit in tons of pollutants extend beyond simply SO2. The total tons of emissions reduced (excluding CO2) is about 8,700 tons/yr, a nearly 5 fold difference from the Sithe estimate.

	Estimated by Sithe			
Parameter	Desert Rock	IGCC	Corrected IGCC	Units
Average Heat Rate	8792	9755	9075	Btu/kw
SO2 Emissions	0.06	0.0229	0.0117	lb/MMBtu
SO2 emissions	2998	1272	590	ton/yr
IGCC benefit		Decrease 1726	Decrease 2408	ton/yr
NOx emissions	0.06	0.06	0.012	lb/MMBtu
NOx emissions	2998	3333	605	ton/yr
IGCC benefit		Increase 335	Decrease 2393	ton/yr
PM emissions	0.01	0.01	0.0063	lb/MMBtu
PM emissions	500	556	317	ton/yr
IGCC benefit		Increase 56	Decrease 183	ton/yr
VOC emissions	0.003	0.003	0.001	lb/MMBtu
VOC emissions	150	167	50	ton/yr
IGCC benefit		Increase 13.5	Decrese 100	ton/yr
CO emissions	0.1	0.04	0.03	lb/MMBtu
CO emissions	4997	2222	1513	ton/yr
IGCC benefit		Decrease 2775	Decrease 3484	ton/yr
Sulfuric Acid Mist e	0.004	0.0023	0.0005	lb/MMBtu
Sulfuric Acid Mist e	200	128	25	ton/yr
IGCC benefit		Decrease 72	Decrease 175	ton/yr
Mercury emissions	9.28E-06	2.52E-06	1.90E-07	lb/MMBtu
Mercury emissions	103	29	19	lb/yr
IGCC benefit		Decrease 75	Decrease 84	lb/yr

65. Sithe did not properly allocate the costs of IGCC to all pollutants controlled. Instead, the incremental cost calculation they performed allocated all costs to SO2 reductions. This failure to allocate the costs to more than one pollutant and the failure to use the correct emission rates for IGCC resulted in a vastly overstated incremental cost per ton of pollutant.

66. Sithe estimates that an IGCC at the Desert Rock site would cost $250/kW to $400/kW higher than a PC plant. Sithe estimates that the cost of electricity using IGCC at the Desert Rock location would be between $3.5/MWh and $6/MWh higher than a supercritical PC at the DREF location. Based upon these cost estimates provided by Sithe, the corrected emissions from IGCC technology that I prepared in the table above, and allocating costs among pollutants controlled according to the USEPA guidance memos found in Thompson Attachments 13 and 14, I calculated the incremental costs of the pollutants controlled (except mercury and carbon dioxide) as shown in the table below. The table shows the incremental cost effectiveness ranges from about $4,000 per ton of pollutant removed to about 8,000/ton of pollutant removed, with the exception of PM which is higher than this range.

					Annual Cost Difference Assuming $3.5 MWH cost increase		Annual Cost Difference Assuming $6MWH Increse	
Pollutant	Desert Rock Annual PC Emissions (tons/yr)	Wt % of Pollutants	IGCC Annual Expected Emissions (tons/yr)	Incremental tons Removed	$ 38,913,672	Incremental Cost($/ton)	$ 66,709,152	Incremental Cost($/ton)
SO2	2,998	25%	590	2,408	$ 9,850,814	4,091	$ 16,887,109	7,013
NOx	2,998	25%	605	2,393	$ 9,850,814	4,117	$ 16,887,109	7,057
PM	500	4%	317	183	$ 1,642,898	8,978	$ 2,816,396	15,390
VOC	150	1%	50	100	$ 492,869	4,929	$ 844,919	8,449
CO	4,997	42%	1,513	3,484	$ 16,419,118	4,713	$ 28,147,060	8,079
Sulfuric Acid Mist	200	2%	25	175	$ 657,159	3,755	$ 1,126,558	6,437
total	11,843		3,100	8,743		-		

67. I consider the range of cost effectiveness levels in the table above to be acceptable. While there is no "bright line" that defines in all cases what is and what is not cost-effective, a number of decisions help establish a range. Several recent permit applications address the cost of sulfur dioxide control. In West Virginia, regulators concluded that coal washing was not BACT for the Longview plant because the average cost per ton of SO2 removed was $18,750 /ton. I reviewed the report of Matt Haber, prepared for the DOJ and USEPA in a civil action against the Baldwin Power Plant in Randolph County, Illinois. It is attached as Thompson Attachment 15. Haber's report estimates BACT for the Baldwin Station over a period of twenty years. As part of his analysis, Haber examined the average cost-effectiveness of pollution control equipment required to installed on eighteen power plants permitted between 1979 and 1999. He concluded that the average cost effectiveness for SO2 controls ranged from a low (when converted to 2001 dollars) of $234/ton to a high of $7,129 per ton. Haber's report also examined historic NOx average cost effectiveness. Between 1990 and 1999, the average cost effectiveness for NOx related pollution control equipment ranged between $934/ton to $13,196/ton. Haber noted that in 2001 EPA issued guidance related to presumptive BACT for NOx control at refineries established $10,000/ton as an upper bound. These cost estimates are often for average cost effectiveness, which is much lower than incremental cost effectiveness calculated in this declaration. Therefore, IGCC technology at the Desert Rock location cannot be eliminated based upon cost effectiveness.

68. The conclusion that the costs posed by an IGCC plant are not unacceptable is supported by recent market activity in which numerous IGCC plants have been proposed by developers.

69. As a result, Sithe incorrectly calculates the benefit computes the incremental cost of $23,000 to $40,000 per ton of SO2 controlled. A more plausible incremental value ranges between $4,500/ton and $7,600/ton, a range I conclude to be cost-effective.

70. Therefore, based upon my experience and the analysis of energy impacts, environmental impacts and economic impacts described above, I conclude that there is not basis to eliminate IGCC from the fourth step of the Top-Down BACT analysis.

Conclusions

71. BACT is selected in step five of the Top-Down BACT analysis based upon the preceding four steps.

72. Based upon my experience, the documents I reviewed, and the analyses described in this declaration, I conclude that IGCC is BACT for the DREF site. The emissions for the permit should correspond to levels that are comparable to the IGCC limits found in table of this declaration entitled "Emission Rates of Proposed DREF Permit Compared to IGCC Requested Rates" using Selexol and SCR.

John Thompson

Date: November 10, 2006

John W. Thompson
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EDUCATION

Master of Business Administration, Washington University, Olin School of Business Executive Program, St. Louis MO, 1999

Bachelor of Science in Chemical Engineering, University of Illinois, Champaign-Urbana, 1982. Graduated with Distinction

EMPLOYMENT

Clean Air Task Force, Boston, MA — *Oct 2001- Present*
Director, Coal Transition Project

- Review new conventional coal-fired power plants permits
- Evaluate economics and environmental characteristics of advanced coal technologies such as coal gasification
- Communicate potential health impacts of power plant pollution
- Review proposed state and federal power plant rules.

Illinois Environmental Council, Springfield, IL — *Nov.1997–Oct 2001*
Director Clean Air Programs

- Developed and lead a campaign to clean-up air emissions from coal-fired power plants on behalf of the Illinois Environmental Council.

Central States Education Center, Champaign, IL — *1984-1997*
Central States Resource Center
Executive Director (1984-Aug. 1996);

- Responsible for fundraising, program, staff development, board relations for the Centers. The Centers are two 35 year-old nonprofit organizations that assist citizens, governments, and businesses on solid, hazardous, and nuclear waste problems.

Illinois Environmental Council, Springfield, IL — *Spring 1984*
Legislative Liaison

Procter & Gamble Inc., Cincinnati, OH — *1982–1983*
Process Development Engineer

PRESENTATIONS

Gasification Performance, Presented at Platts 2nd Annual IGCC Symposium, Pittsburgh PA, May 10, 2006.

IGCC's Environmental Performance and Role in Mitigating CO2 Emissions, Infocast's IGCC Project Development and Finance Seminar, St. Louis, MO, November 14-16, 2005.

Public perception of Gasification, Presented at MIT Carbon Sequestration Forum VI, Cambridge MA, November 3, 2005.

Integrated Coal Gasification Combined Cycle (IGCC) Environmental Performance, Presented at Platts IGCC Symposium, Pittsburgh PA, June 2-3, 2005.

View from the States, Presented at Workshop on Gasification, sponsored by U.S. Department of Energy, the National Association of Regulatory Commissioners, the Gasification Technologies Council, and the Southern States Energy Board, United State Environmental Protection Agency, Knoxville TN, April 12-13, 2005.

Integrated Coal Gasification Combined Cycle (IGCC): Environmental Impacts and Policy Implications, Presented at STAPPA/ALAPCO Fall Membership Meeting, Couer d'Alene ID, October 27, 2004.

Coal Gasification-Air Pollution and Permitting Implications of IGCC, Presented at USEPA's Air Innovations Conference, Chicago, IL, August 2004.

The BACT Analysis: Does IGCC Meet the Test?, Presented at Workshop on Gasification Technologies, sponsored by U.S. Department of Energy, the National Association of Regulatory Commissioners, the Gasification Technologies Council, and the Southern States Energy Board, Indianapolis, IN, June 2004.

Coal Gasification: Hedging Against Climate Change in the Power Sector, Presented at the Western Governors' Association Energy Summit, Albuquerque New Mexico, April 14, 2004

IGCC as LAER/BACT for the Production of Electricity from Coal, presented at the 20th Annual International Pittsburgh Coal Conference, Pittsburgh PA, September 15-19, 2003.

OTHER ACTIVITIES

Co-Chair, Technologies Subcomitttee, Clean Coal Task Force, Westerrn Governors' Association, May 2005- Present

KENTUCKIANA ENGINEERING COMPANY, INC.

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311 Townepark Circle, Suite 100
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Providing Solutions with a Future

August 09, 2006

Mr. John Lyons, Director
Kentucky Division for Air Quality
803 Schenkel Lane
Frankfort, Kentucky 40601

RE: Cash Creek May 2006 PSD Application Errata 1

Dear Mr. Lyons,

During review of the Cash Creek Generating Station (CC) PSD application dated May 4, 2006; several items were discovered that needed to be updated or corrected. The majority of these updates include corrections to the DEP7007 application forms. Portions of the application forms had not been changed to reflect the revised emission limits and operating characteristics described in the narrative and modeling portions of the application. There were also typographical errors identified within the narrative that are being corrected at this time. Additionally, a warning message associated with the 1990 PM_{10} preliminary impact modeling was reviewed and corrections have been made. Also included as Attachment 1 to this document are responses to the comments on the application from KYDAQ received on June 19, 2006, in the form of a Notice of Deficiency. Following is an itemized list of the items included in this submission along with the page being amended if applicable.

Application Forms:
The following revised application forms are included in Attachment 2 of this letter.

Emission Unit - Turbine 1, HRSG 1:	Pages: 9, 12, 13, 14, 15, 16
Emission Unit - Turbine 2, HRSG 2:	Pages: 21, 22, 24, 25, 26, 27, 28
Emission Unit - Auxiliary Boiler:	Pages: 33, 34, 35, 36, 37, 38, 39
Emission Unit - Flare 1:	Pages: 41, 42, 43, 44, 45, 46, 47, 48
Emission Unit - Thermal Oxidizer TO30:	Pages: 50, 51, 52, 53, 54, 55, 56, 57
Emission Unit - Coal Handling CAREA1:	Pages: 59, 60, 61, 62, 63, 64, 65, 71, 72, 73, 74, 75
Emission Unit - Cooling tower:	Pages: 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95
Emission Unit - Emergency Fire Pump FP:	Pages: 99, 100, 101, 102, 103, 104, 105
Emission Unit - Storage Tank DSFT, T2, T3:	Pages: 108, 109, 110, 111, 112, 113, 114
Emission Unit - Cold Solvent Parts Cleaner CCD1:	Pages: 115, 116, 117, 118, 119, 120, 121
Emission Unit - Slag Handling, Hauling & Landfill:	Pages: 122, 123, 124, 125, 126, 127, 128, 129, 130
Insignificant Activities:	Page: 131

Corrections to the application narrative:

The following revised pages are being submitted to address typographical errors or omissions found during review of the application narrative.

A Glossary of terms used in the application has been included with this submittal and should be placed after the list of Appendices and prior to Section1 Tab of Volume I of the application. This list of terms is being provided to clarify some of the abbreviations used in the application.

Section 3:
Regulatory Applicability - The following corrections are included in Attachment 3 to this document.

General Changes to Section 3:
Several items in Section 3 have been revised to more accurately reflect the CC. Many of these changes are corrections to typographical errors and may not be individually listed below. A complete revised copy of Section 3 has been included in attachment 3 and should replace Section 3 of the May 4, 2006, application.

Specific Changes to Section 3:

Section 3.1, Page 3-4, Table 3-2: The table has been corrected to reflect the predicted NO_x and particulate matter emissions.

Section 3.2.1: A final rule was published in the February 2006 Federal Register adding IGCC facilities to the applicability section of 40 CFR Subpart Da – Standards of Performance for New Electric Utility Steam Generating. The previous application incorrectly listed 40 CFR 60 Subpart GG-Standards of Performance for Stationary Gas Turbines as applicable to the IGCC. This document corrects this error and details the requirements as they apply to CC.

All of Section 3: At the request of KYDAQ the word "adopted" has been replaced by the word "incorporated" when citing applicable Kentucky regulations that incorporate federal requirements.

Subsection 3.6.1: Regulatory citation 401 KAR <u>52:160</u>-NO_x Trading Program was corrected to read 401 KAR <u>51:160</u>-NO_x Trading Program

Section 4:
Best Available Control Technology Demonstration - The following corrections are included in Attachment 4 to this document

General Changes to Section 4:
Several items in Section 4 have been revised to more accurately reflect the CC. One example is the removal of VOC controls from the BACT analysis and summary tables. Since CC will not emit VOC equal to or greater than PSD significance levels a BACT review that includes VOC is

not required. The inclusion of VOC in the previous BACT analysis was determined to be confusing. The BACT analyses for ancillary devices, including the auxiliary boiler and fire water pump, have been expanded along with the discussion regarding control option feasibility. Additionally, typographical errors and omissions have also been corrected in this revision. A complete revised copy of Section 4 has been included in attachment 4 and should replace Section 4 of the May 4, 2006, application. Following are a few of the more specific changes made to Section 4.

Specific Changes to Section 4:
Section 4-1: The narrative incorrectly stated that the proposed project would be in Christian County, Kentucky. The language was corrected to reflect the proposed project's location in Henderson County, Kentucky.

Table 4-1: The potential emissions listed in the table for NO_x and PM_{10} have been corrected to match the calculated potential emissions as described in Section 5.

Section 4.6.8.4: The BACT emission limits and averaging time for SO_2 and H_2SO_4 when firing natural gas in the combustion turbines have been corrected.

Table 4-20: The Increase in annual cost for Rectisol was incorrectly listed as $3,727,324. This was revised to reflect the correct annual cost of $3,727,234.

Section 4.7, Table 4-22: Added H_2SO_4 and the associated limit to the pollutant list when firing natural gas in the combustion turbines.

Section 4.6.11: The BACT discussion for CO was revised to follow the preferred top down approach with regards to evaluating control alternatives.

Section 4.6.13.1: Corrected the reference to Table 4-24 to read Table 4-25

Section 4.6.13.2: Corrected the reference to Table 4-25 to read Table 4-26.

Section 4.8: An hour by hour discussion of Start-up, Shut-down, and Malfunction was added as Section 4.8.

Section 5:
Emission Estimates - The following corrections are included in Attachment 5 to this document.

General Changes to Section 5:
Several items in Section 5 have been revised to more accurately reflect the CC. Many of these changes are corrections to typographical errors and may not be individually listed below.

Specific Changes to Section 5:
Section 5.1, Page 5-2, Table 5-1: Maximum Emission Rates for the Cash Creek Generating Station. The table did not reflect the correct particulate emissions for several of the emission points. However, the calculations detailed in Section 5 are correct. To eliminate confusion a revised Table has been included in this submittal along with a complete POC table listing all emission points associated with the facility. The POC table should be placed after the application forms in Appendix A of the application.

Table 5-1 has also been corrected to reflect the predicted emissions for NO_x and particulate matter.

Sections 5.2.2 and 5.2.3, Pages 5-6, 5-10, 5-14, and 5-15, Tables 5-2, 5-4, and 5-5: A sample calculation for mercury emissions has been added. The tables have been updated to reflect a revised mercury emission limit based on Subpart Da as discussed in Section 3.

Section 6:
Air Quality Analysis - The following corrections are included in Attachment 7 to this document

Specific Changes to Section 6:
Page 6-50, Table 6-18: PM_{10} PIA SMC Modeling Results Using Site LULC
A warning message indicating a met data mismatch was listed with the modeling outputs for the PM_{10} PIA 1990 site location modeling run. Upon reviewing this error a correction was made and the model was rerun. The revised modeling run resulted in slight impact variations from those in the original modeling and these are listed in the revised Table 6-18. However, it should be noted that the results of this single modeling run did not change the maximum predicted high first high or high second high PM_{10} impacts for the facility.

Each of the pages to be placed in the application includes an ER-1 in the footer so it can be easily recognized as an errata page. If any additional changes are submitted they will be marked using the next successive number corresponding to the submission.

If you have any questions regarding this letter or its attachments please contact me at (502) 489-8074 ext 300 or bhandy@kecco.net.

Best Regards,

Bryan C. Handy

Bryan Handy, Project Manager

cc:/ Mr. Michael McInnis – Cash Creek Generation, LLC

Attachments

ATTACHMENTS

ATTACHMENT 1	Response to June 19, 2006 comments from KYDAQ
ATTACHMENT 2	Revised Application Forms
ATTACHMENT 3	Revisions to Section 3
ATTACHMENT 4	Revisions to Section 4
ATTACHMENT 5	Revisions to Section 5
ATTACHMENT 6	Revisions to Section 6

ATTACHMENT 1

Response to June 19, 2006 KYDAQ Comments

respecting the

Cash Creek Generating Station PSD Application

Response to June 19, 2006 KYDAQ Comments

respecting the

Cash Creek Generating Station PSD Application

Each comment is reproduced below followed by Cash Creek Generation's (CCG) response.

Comment 1:

A Continuous Assurance Monitoring (CAM) Plan is required to be submitted with the Title V application for facilities with emission units incorporating pollution control equipment pursuant to 40 CFR Part 64, and emissions exceed 100 tons per year of any criteria pollutant.

Response 1:

After reviewing the compliance assurance monitoring (CAM) plan requirements it was determined that CAM does not apply to the emissions from CC. This determination is based on the definition of applicability found at 40 CFR 62.2 which states:

a) *General applicability.* Except for backup utility units that are exempt under paragraph (b)(2) of this section, the requirements of this part shall apply to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria:

(1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of this section;

(2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and

(3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, "potential pre-control device emissions" shall have the same meaning as "potential to emit," as defined in §64.1, except that emission reductions achieved by the applicable control device shall not be taken into account.

(b) *Exemptions*—(1) *Exempt emission limitations or standards.* The requirements of this part shall not apply to any of the following emission limitations or standards:

(i) Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act.

(ii) Stratospheric ozone protection requirements under title VI of the Act.

(iii) Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act.

(iv) Emission limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions within a source or between sources.

(v) An emissions cap that meets the requirements specified in §70.4(b)(12) or §71.6(a)(13)(iii) of this chapter.

(vi) Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1. The exemption provided in this paragraph (b)(1)(vi) shall not apply if the applicable compliance method includes an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device (such as a surface coating line controlled by an incinerator for which continuous compliance is determined by calculating emissions on the basis of coating records and an assumed control device efficiency factor based on an initial performance test; in this example, this part would apply to the control device and capture system, but not to the remaining elements of the coating line, such as raw material usage).

A CAM plan is required for an emission unit if all three of the conditions listed in 40 CFR 62.2(a) 1 to 3 are met. As discussed below no pollutant-specific emissions unit meets all three of the requirements.

The applicability of CAM is based on a per unit basis and other than the CT/HRSGS no controlled units at CC have potential pre-control device emissions that are equal to or greater than 100 percent of the amount required for a source to be classified as a major source. As an example the approach used to determine CAM applicability for one of the material handling units follows:

The emissions resulting from the transfer of coal from the barge unloading conveyor to the facility receiving conveyor have an estimated pre-controlled emission rate of 1.1 tons per year. The transfer point will be controlled by enclosure, suppressant, baghouse or other feasible controls capable of meeting the BACT requirements included in the application. Since the unit is controlled it was reviewed for CAM applicability; however, since the total uncontrolled emissions are estimated to be 1.1 tons per year CAM does not apply. The requirements state the emissions must be equal to or greater than 100 percent of the amount required for a source to be classified as a major source. For CC the amount required to be classified as a major source is 100 tons per year.

As discussed above the only emission units with pre-controlled pollutant emissions greater than 100 tons per year are the CT/HRSGs and the only pollutant meeting this requirement is NO_x. However, NO_x emissions from the CT/HRSGs are exempt from CAM requirements because they are subject to the post November 15, 1990, NSPS found at 40 CFR 60 Subpart Da[1] and the acid rain requirements. Based on the exemptions allowed by regulation, NO_x emissions from the CT/HRSGs are not subject to CAM requirements.

Since all of the remaining units at CC are similar to the transfer unit discussed in the example above, and no remaining individual unit has a pre-controlled emission rate greater than 100 tons per year, a CAM plan is not required for the CC.

Comment 2:

Please note our concern about the level of detail and lack of specificity in some areas. In particular numerous entries in the permit application forms are marked "To Be Determined" (TBD). Although we understand the difficulties of providing every detail at this stage of a long-term project, the pervasive lack of specificity places DAQ in an awkward position and opens the door to even more public criticism of the project than would occur otherwise.

Response 2:

All currently available information has been included in the application for each process and piece of equipment. However, portions of the DEP7007 application forms involve requests for specific component information that is not applicable or not available for the affected process or equipment at this time. For example, information regarding vendor name, equipment number, operating ranges, etc. is not typically available until Engineering, Procurement, and Construction ("EPC") contractor is selected and released to build the facility. The EPC contractor is not released to begin procurement until all applicable environmental and building permits are obtained. After release, the EPC contractor initiates a procurement process with vendors of specific equipment that will satisfy the general performance requirements of the facility and the

[1] Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978; Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

specific equipment design specifications. Each equipment component is put out for bid. The selected equipment vendor then finalizes the design of the equipment and its associated operating parameters necessary to meet the requirements of the project. Since this information is not available until after the permitting process is complete and an EPC contractor is selected and released, it is not available for inclusion in the application. In those instances where the missing information will be available in the future, the forms were noted with "To Be Determined" ("TBD"). For instances where the requested information is not applicable, that information was noted as being "Not Applicable" ("NA").

Comment 3:

The following Corrections should be made to the application (note the correction has been underlined);

a) Page 3-8 under - 3.2.1 40 CFR 60 Subpart GG – Standards of Performance Gas Turbines (adopted by reference in 401 KAR 60:005§2(nn))

   Should read 3.2.1 40 CFR 660 Subpart GG Standards of Performance Gas Turbines (<u>incorporated</u> by reference in 401 KAR 60:005§3(nn))

b) Page 3-9 under - 3.2.1 40 CFR 60 Subpart Y ... (adopted by reference in 401 KAR 60:005§2(ff))

   Should read 3.2.1 40 CFR 660 Subpart Y... (<u>incorporated</u> by reference in 401 KAR 60:005§3(ff))

c) Page 3-9 under - 3.2.1 40 CFR 60 Subpart Db ... (adopted by reference in 401 KAR 60:005§2(d))

   Should read 3.2.1 40 CFR 660 Subpart Db... (<u>incorporated</u> by reference in 401 KAR 60:005§3(d))

d) Page 3-13 under - 3.6.1 401 KAR 52:160 - NO_x Trading Program

   Should read 401 KAR <u>51</u>:160

Response 3:

a) The correction has been made and the revised language has been included in Attachment 3.
b) The correction has been made and the revised language has been included in Attachment 3.
c) The correction has been made and the revised language has been included in Attachment 3.
d) The correction has been made and the revised language has been included in Attachment 3.

Comment 4:

4.1 Overview – Cash Creek Generation, LLC ("CCG") is proposing to build the Cash Creek Generating Station ("CC") in Christian County, Kentucky.

Should read … Cash Creek Generation, LLC ("CCG") is proposing to build the Cash Creek Generating Station ("CC") in Henderson County, Kentucky.

Response 4:

The correction has been made and the revised language has been included Attachment 4,.

Comment 5:

The NOx potential emissions listed in Table 4-1: CC Source Wide Emissions Subject to BACT Review should read 629 instead of 133.

Response 5:

The correction has been made and the revised language has been included Attachment 4.

Comment 6:

The Increase in Annual Cost listed for Rectisol™ in Table 4-20: Cost of Rectisol™ and Selexol™ should be $3,727,234 instead of $3,727,324.

Response 6:

The correction has been made and the revised language has been included Attachment 4.

Comment 7:

Page 4-58 under
A brief description of the NOx control technologies listed in Table 4-16 are provided below.
Should read - A brief description of the NOx control technologies listed in Table 4-21 are provided below.

Response 7:

The correction has been made and the revised language has been included Attachment 4.

Comment 8:

Page 4-58 under
4.6.10.1 Economic Impacts of NO_x Control Selected – While the including SCR in the design of the facility dos increase the costs the increase is nominal and offset by the benefits associated with the reduction of NO_x emissions. Should read - While including SCR in the design of the facility dos increase the costs the increase is nominal and offset by the benefits associated with the reduction of NO_x emissions.

Response 8:

The correction has been made and the revised language has been included Attachment 4.

Comment 9:

Page 4-62 under

a) 4.6.13.1 Auxiliary Boiler … BACT emission limits for the auxiliary boiler are set out in Table 4-24. Should read …BACT emission limits for the auxiliary boiler are set out in Table 4-25.
b) 4.6.13.1 Firewater Pump … BACT emission limits for the natural gas fire pump are set out in Table 4-25. Should read …BACT emission limits for the natural has fire pump are set out in Table 4-26.

Response 9:

The correction has been made and the revised language has been included Attachment 4.

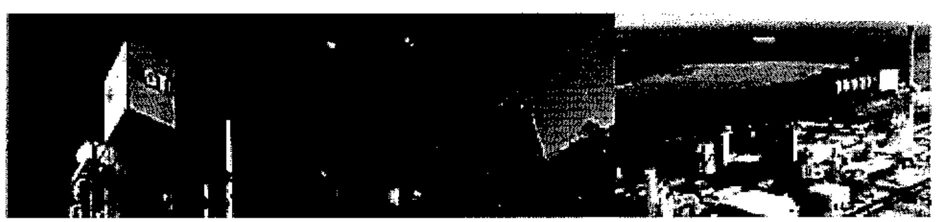
GASIFICATION TECHNOLOGIES 2005
San Francisco, CA,
October 11 2005

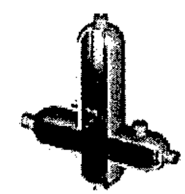
E-Gas Applications for Sub-Bituminous Coal

Ron Herbanek, Mechanical Engineering Director, E-GAS
Thomas A. Lynch, Project Development Manager

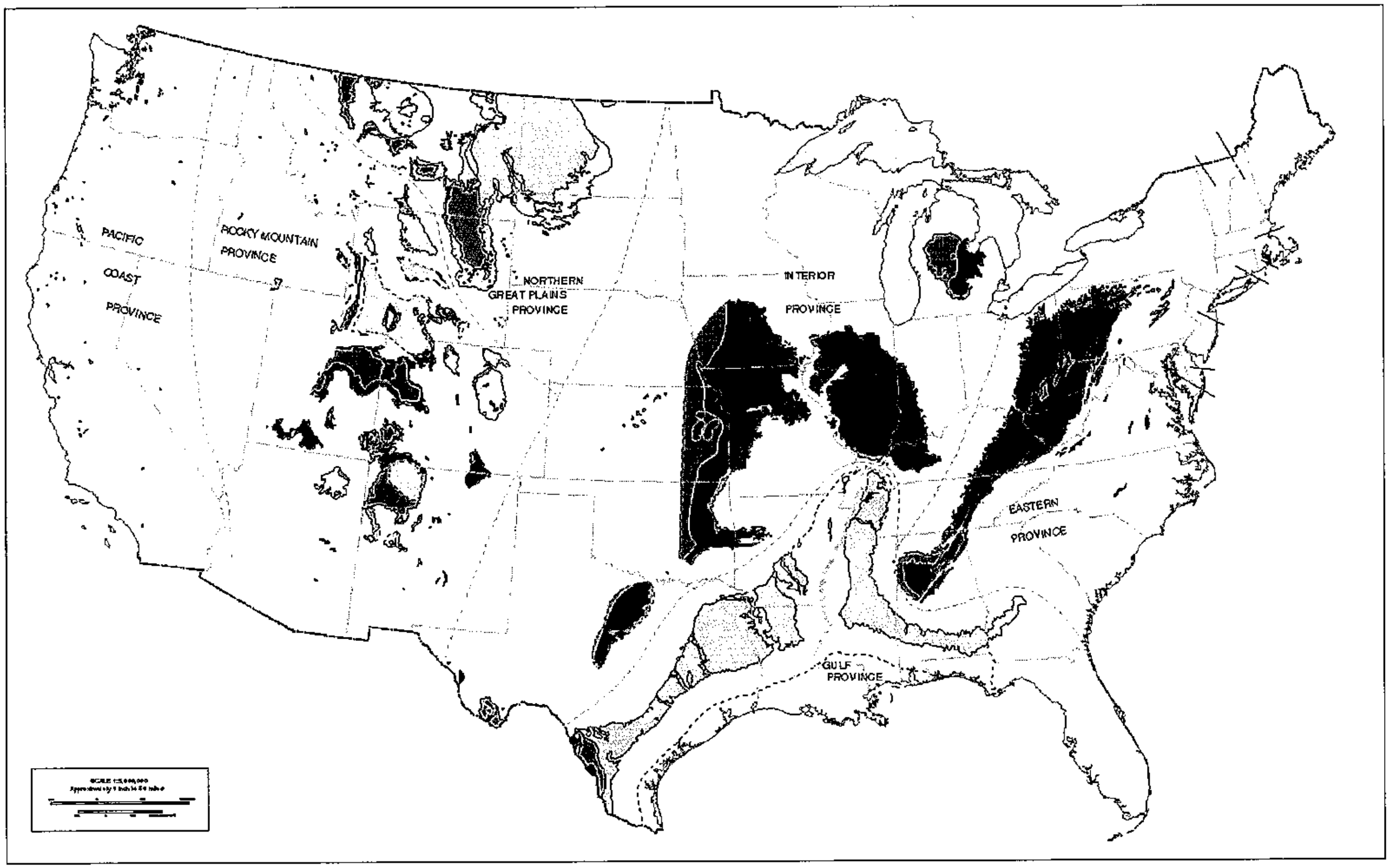
ConocoPhillips

E-Gas
Technology for Gasification





U.S. Coal Resource Regions (Lower 48)



E-Gas Technology for Gasification

Source: Energy Information Administration

ConocoPhillips

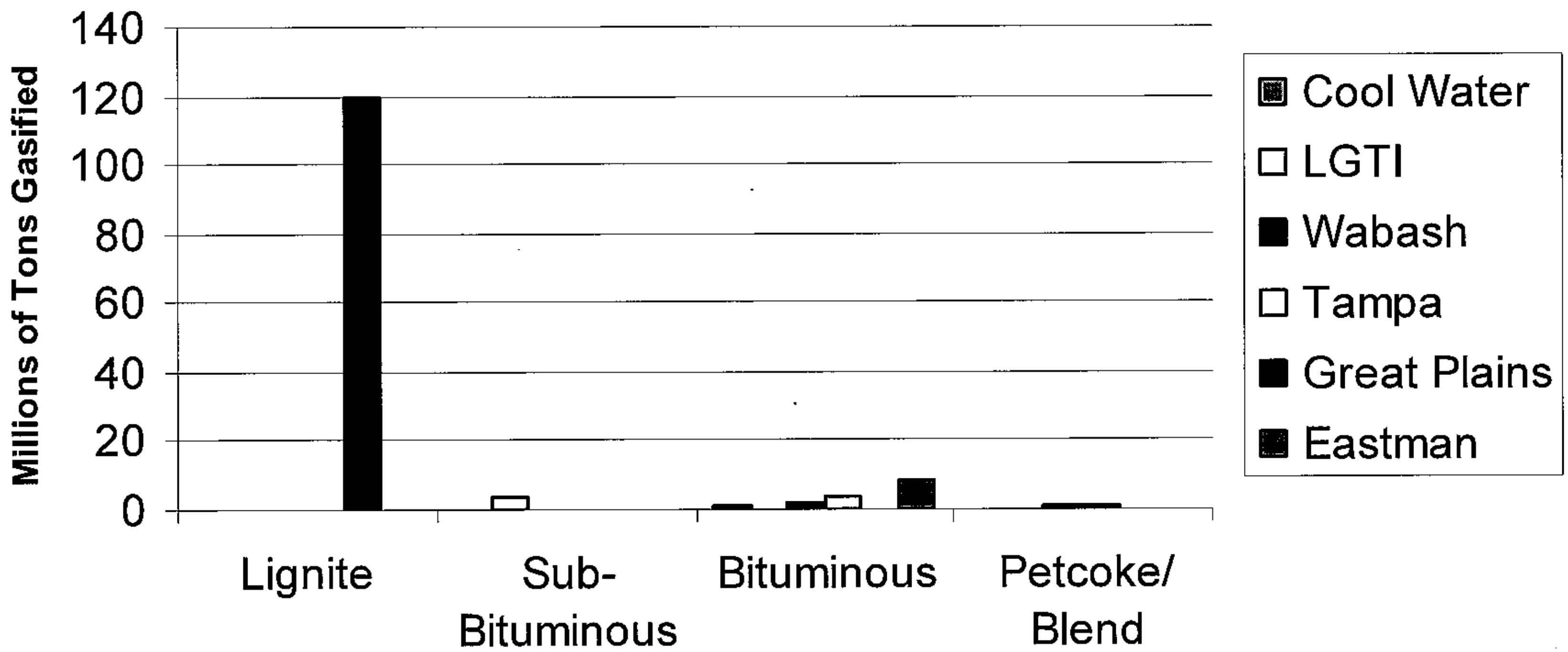
Coal - THE US Energy Resource

- Demonstrated Reserves
  - 508 B tons (275 B tons recoverable)
  - 185 B tons (36%) Sub Bituminous
- Current Annual Production (2004)
  - 1.1 B tons
  - 0.37 B tons (34%) Sub Bituminous
- Electric Utility Consumption (2004)
  - 1.0 B tons (>90%)

Source: Energy Information Administration & National Mining Association

Modern Era Coal Gasification – Power & Industrial

Coal Used: 94% Lignite



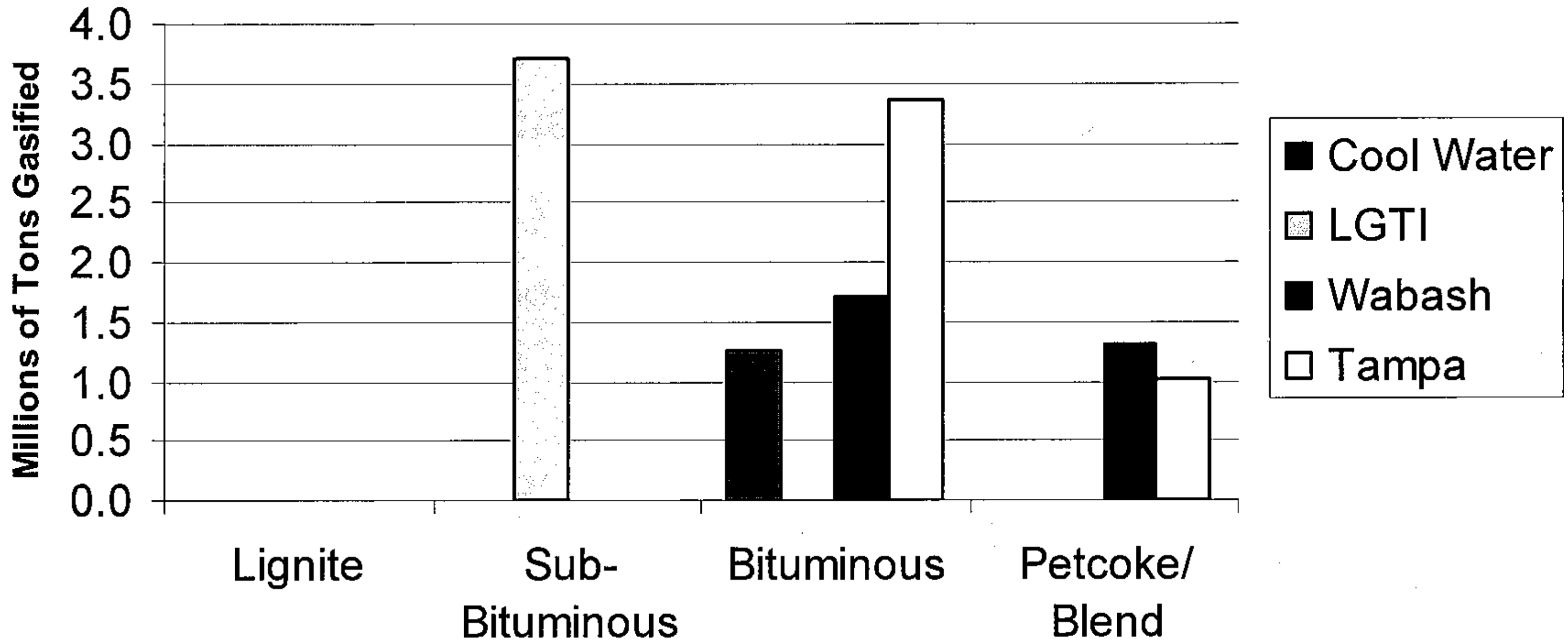
Source: DOE NETL

E-Gas Technology for Gasification

ConocoPhillips

U.S. Coal-to-Power Gasification

Coal Used: 37 % Sub-Bituminous - 63% Bituminous

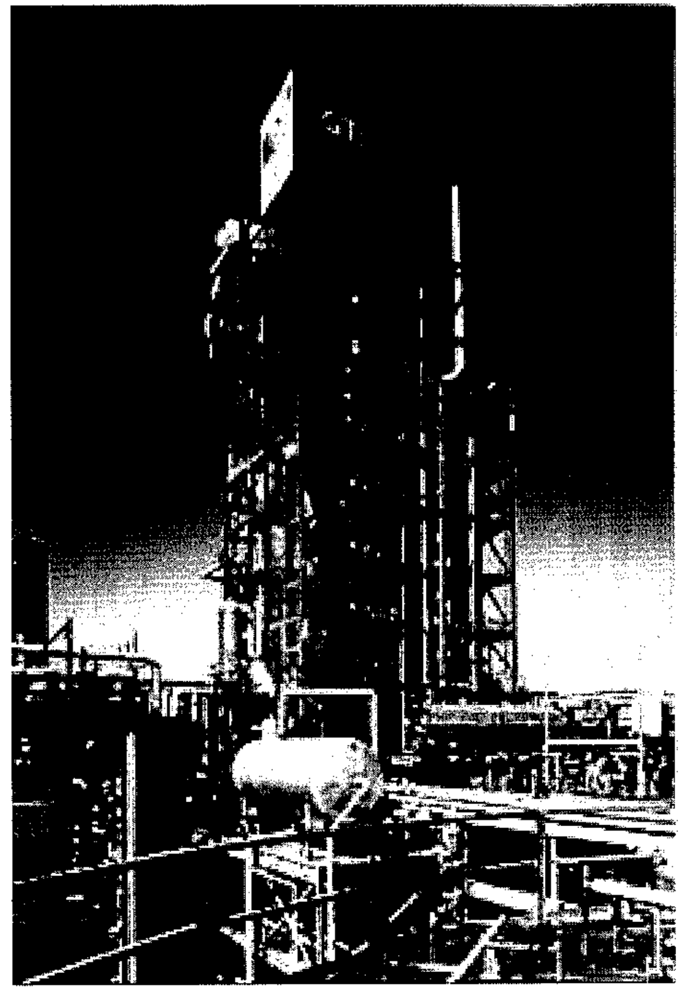


Source: DOE NETL

LGTI – Louisiana Gasification Technology, Inc

One Third of the Coal-to-Power Gasification in U.S.

- 2400 tpd Sub Bituminous coal feed
- Operated 1987 – 1995
- Processed 3.7 MM tons
- Fueled (2) S-W SGT6-3000E GTGs (a.k.a W501D5)
- 75% Availability (1994-1995)



E-Gas Technology for Gasification

ConocoPhillips

Feed Design Considerations

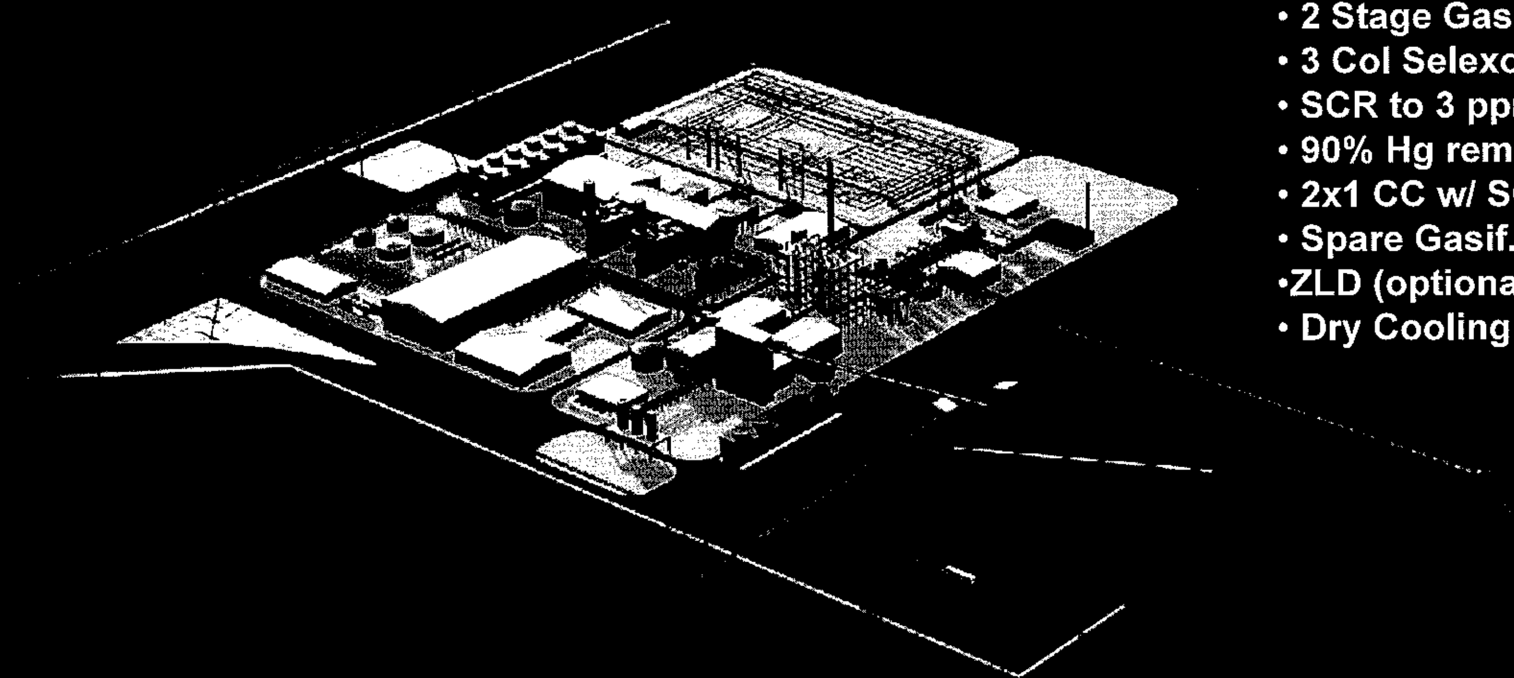
Attribute	Impact	Mitigation [1]
Moisture	High moisture = lean Slurry (50-55%)	Slurry heating plus FSQ in 2 stage gasifier improves HR
Sulfur	Low Sulfur = lean acid gas	Selexol ™ provides high CO_2 selectivity
Ash	Slag quantity	N/A – high ash degrades HR, low ash requires flux addition
Slurry-ability	Moisture limits slurry concentration	N/A - (ALS and feed drying are not economical)
T_{250}	Determines 1st stage operating temperature	N/A – High value requires flux addition
Fixed Carbon	Determines feed rate & RXR sizing	N/A - “spike” with petcoke
Oxygen	Determines ASU size	N/A – (high O2 reduces ASU size)

E-Gas Technology for Gasification

Notes:
[1] N/A indicates mitigation not applicable to /required for Sub Bituminous feed

ConocoPhillips

600 MW Sub Bituminous IGCC Design Template



FEATURES:
- No coal prep required
- 2 Gasification Trains
- 2 Stage Gasification (FSQ)
- 3 Col Selexol ™ AGR
- SCR to 3 ppm NOx
- 90% Hg removal
- 2x1 CC w/ SGT6-5000F GTGs
- Spare Gasif. Train (optional)
- ZLD (optional)
- Dry Cooling (optional)

E-Gas Technology for Gasification

3D Rendering Provided by Fluor/Siemens/ConocoPhillips

ConocoPhillips

600 MW Sub Bituminous IGCC Case Description

	Midwest	Mine Mouth
Site Conditions	500 ft, 50 F avg. amb.	5,000 ft, 45 F avg. amb.
Q Coal (AR, HHV), Btu/lb	8,340	
Composition:		
Carbon (dry basis), wt%	69.07	
Sulfur (dry basis), wt%	0.53	
Ash (AR), wt%	5.32	
Moisture (AR), wt%	30.24	
Acid Gas Removal	3 Col. Selexol ™	
Steam Conditions psig/F	1800/1050/1050	
Heat Rejection	Cooling Tower	Air Cooled
GTG Emissions Control	15 ppm NOx (diluent) plus SCR	
Process Wastewater	SW recycle via R.O.	SW recycle + ZLD

E-Gas Technology for Gasification

ConocoPhillips

600 MW Sub Bituminous IGCC Estimated Plant Performance

	Midwest	Mine Mouth
Feed Rate, tpd (AR)	8,341	7,259
Oxygen, tpd (95% vol)	4,732	4,132
Gross Power, MW	778.1	671.4
Aux. Power, MW	133.8	115.9
Net Power, MW	644.3	555.9
Net H.R., Btu/kWh (HHV)	8,996	9,075
Emissions [1]:		
NO_x, lb/MMBtu	0.02	
SO_2, lb/MMBtu	0.01	

Notes:
[1] Target permit levels

E-Gas Technology for Gasification

ConocoPhillips

600 MW Sub Bituminous IGCC Plant – Indicative Economics

ECONOMIC PARAMETERS

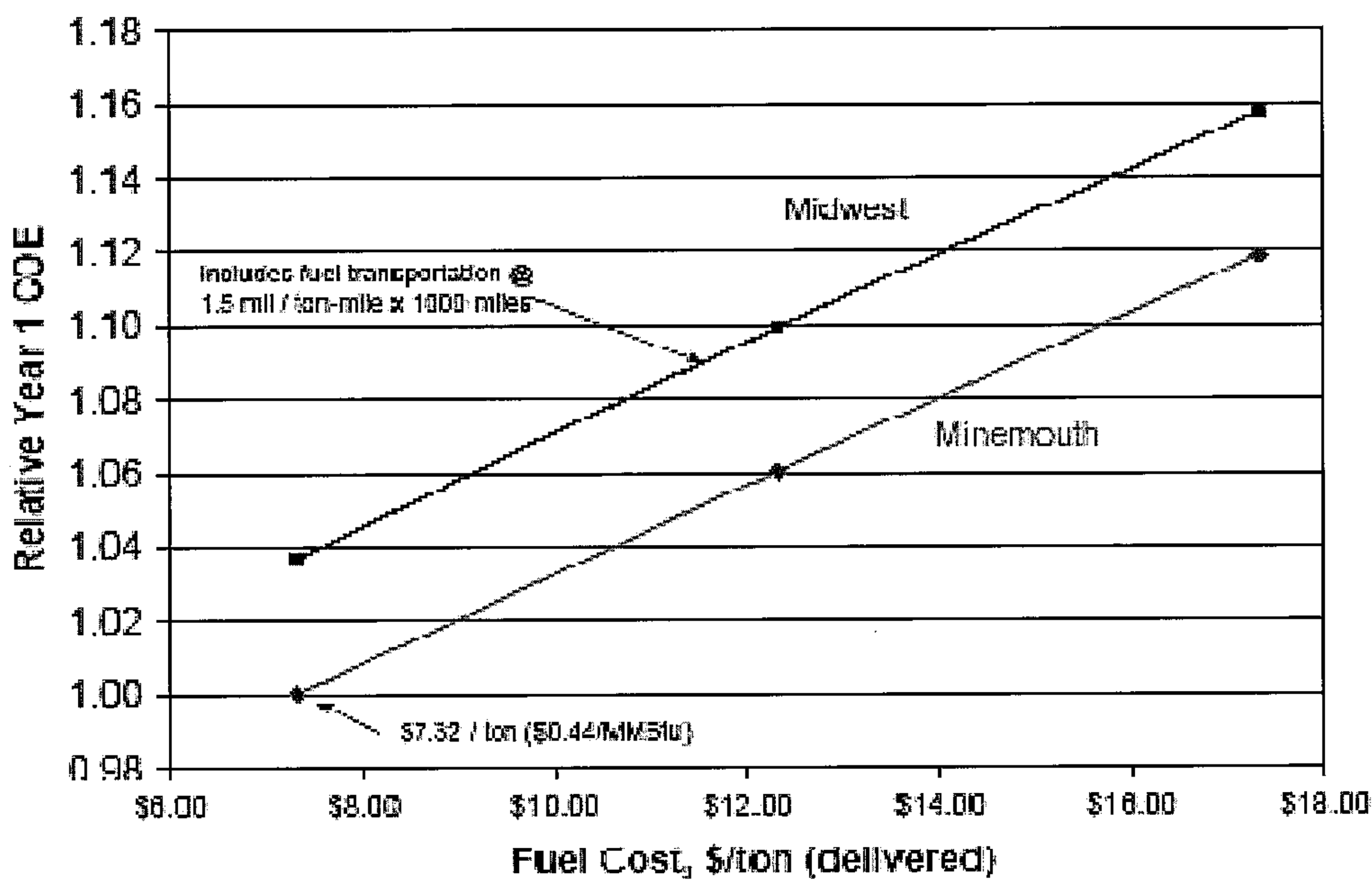
	Midwest	Mine Mouth
EPC Cost, $MM [1]	935 - 1131	868 - 1051
Owner's Costs, $MM [2]	70	150
Ann. O&M, $MM [3]	37	39
Availability, % [4]	80 - 85	80 - 85

Notes:
[1] ISBL, Overnight cost, $3Q05 (incl. 20% P&C)
[2] OSBL costs (transmission), Permitting, FEED, License, Land, etc.
[3] O&M (non-fuel) calculated at ~4% of EPC
[4] Two gasification trains, no spare

E-Gas Technology for Gasification

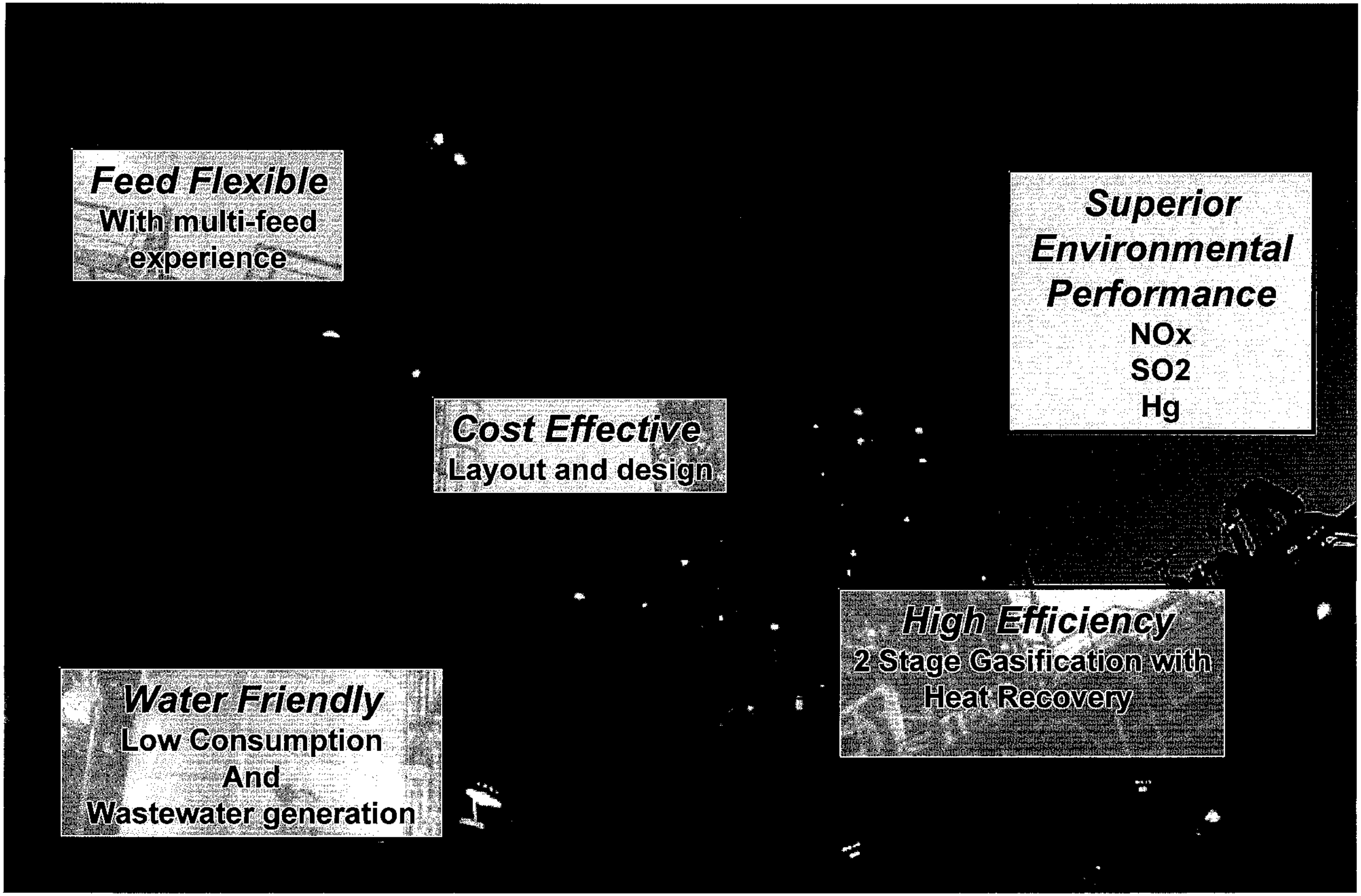
ConocoPhillips

COE vs. Fuel Cost ($2010)



E-Gas Technology for Gasification

ConocoPhillips



E-Gas Technology for Gasification

ConocoPhillips

Refinery IGCC plants are exceeding 90% capacity factor after 3 years

By Harry Jaeger

Steep learning curves for commercial IGCC plants in Italy show annual capacity factors of 55-60% in the first year of service and improvement to over 90% after the third year.

EniPower is commissioning a 250 MW IGCC plant that will burn syngas produced by gasification of residues at an adjacent Eni Sannazzaro refinery in north central Italy.

Based on commercial experience with earlier plants, project engineers predict the annual capacity factor (measure of profitability) of the Sannazzaro plant should match if not outperform them, especially in the critical early years. Specifically:

☐ **ISAB Energy.** Asphalt-based 520 MW plant built by Ansaldo Energia went from a capacity factor of 61% in 2000, first year of commercial operation on syngas, to 93% in 2004.

☐ **Sarlux Saras.** Residues-based 545 MW plant went from a capacity factor of 55% in 2001, first year of commercial operation on syngas, to 90% in 2004.

☐ **Api Energy.** Residues-based 280 MW plant went from a capacity factor of 66% in 2001, first year of commercial operation on syngas, to 94% in 2004.

The Eni Sannazzaro IGCC plant, nominally rated at 250 MW net ouput, is designed around a multi-shaft 1 x 1 Ansaldo manufactured Siemens V94.2K combined cycle module and Shell Global Solutions gasification process.

The combined cycle unit is located at EniPower's 1050 MW station in Ferrera Erbognone along with two 400 MW natural gas-fired Ansaldo V94.3A.2 combined cycle (multi-shaft 1x1 configurations) plants.

Ansaldo Energia re-designed and tested the original Siemens burner design in two different test programs, at Ansaldo's combustion center and the Enel Laboratories R&D center in Italy.

Startup date

The IGCC combined cycle has been operating on natural gas while the gasification system is undergoing commissioning and testing within the refinery battery limits.

The gas turbine recently began commissioning and was expected to begin commercial operation on syngas in mid-2006 selling electricity into the national grid.

The gasification system also will export superheated steam and hydrogen within the refinery.

Originally, the switchover to syngas operation was to take place by the end of 2005. However, an apparent delay in commissioning, along with other refinery modifications, pushed the date off. The actual switchover is to take place in March 2006.

Shell's gasification process has been widely used for industrial applications worldwide; eight coal gasification units are under construction in China alone.

It was selected for the coal-based IGCC demo plant at the Nuon Buggenum power station, The Netherlands, which has been operating for about 12 years. Also for the commercial Pernis refinery IGCC project in The Netherlands that started operations in 1997.

Shell gasifier trains

At the Sannazzaro plant, two 50% oxygen-blown gasifiers will process about 600 tons a day of refinery residues from the Eni Refinery (formerly Agip Petroli).

According to project engineers, Eni chose the Shell gasification process in the interest of achieving higher net plant efficiencies for the intended cogeneration of electricity and steam.

Unlike the Texaco quench-type gasifiers (now GE Energy) used by the other IGCC plants in Italy, the Shell gasifiers are fitted with a heat recovery unit that produces high pressure (84 barg) superheated steam for use in the refinery.

Following heat recovery, the syngas goes through a catalytic hydrolysis unit where COS and HCN are converted to H2S and NH3, respectively.

After this, the syngas is washed in a water-spray column, to absorb the ammonia, and the H2S is then removed in the acid gas removal unit using a chemical solvent absorption process (MDEA-Dow).

Resultant hydrogen sulfide-rich waste gas is sent to a Claus sulfur recovery unit at the refinery to produce a solid sulfur product.

Following acid gas removal, the desulfurized syngas is forwarded to a hydrogen removal and recovery unit that produces pure hydrogen which the refinery uses to produce cleaner fuels.

Co-firing option

Final composition of the syngas, and, therefore its heating value and Wobbe index, will vary depending upon the amount of hydrogen off-take for refinery use.

When the ratio of hydrogen to carbon monoxide is too low (depending on gas turbine combustion system design specs) up to about 10% of natural gas fuel can be added for operation in a co-firing mode.

The syngas modified V94.2K gas turbine is equipped with a dual fuel combustor to operate on natural gas alone as a backup fuel when the gasifier is shut down for scheduled maintenance or service.

Although a Siemens design, the gas turbine was built by Ansaldo (under license) and equipped with its own designed and patented burners.

The "K" designation indicates the addition of one compressor stage to meet requirements of operating with syngas with no (or only partial) integration of the air separation unit.

Ansaldo Energia notes that it performed all of the combustion and fuel system modifications needed to burn and operate on the syngas fuel.

For NOx control purposes, to meet a local 25 ppm environmental limit, dilution steam from the combined cycle's heat recovery steam generator is injected into the syngas before it is fed to the gas turbine.

At an H2 to CO ratio of approximately 1 to 1, and with water vapor comprising about 35% of the gas by volume, the as-delivered lower heating value of the fuel gas is on the order of 175 Btu/scf.

Europe forging ahead

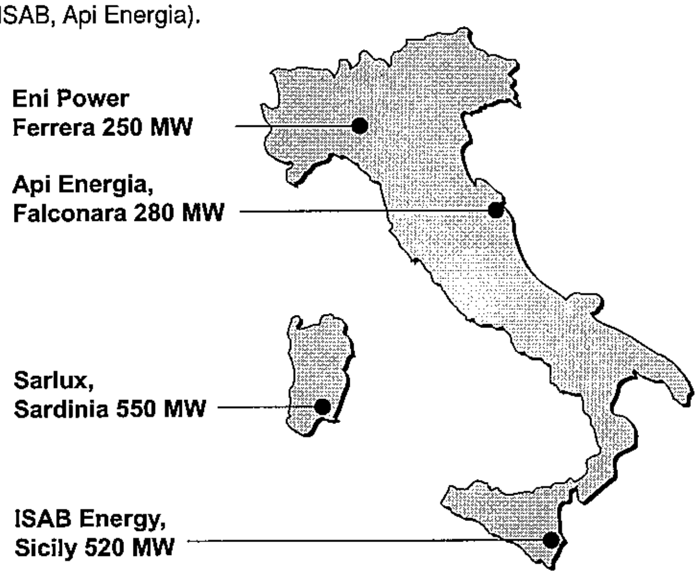
Although many utilities and state regulatory commissions in the U.S. regard IGCC as "emerging" technology, Europe has already acquired a solid base of commercial IGCC design and operating experience (lessons learned) for future projects.

Since 1995, about 2500 MW of IGCC capacity using heavy petroleum residues in a refinery environment has been installed worldwide.

Italy, with IPP partners from the U.S., has commissioned four refinery-based IGCC plants for commercial operation since 2000 with an installed generating capacity of about 1600 MW.

Two of those plants, rated over 500 MW each, use gasification technology supplied by Texaco (now GE Energy) and were built by EPC teams that included Snamprogetti and Foster Wheeler Italiana of Milan.

IGCC projects. Refineries are generating electric power, steam and hydrogen from excess low-grade residues. Developed as joint ventures with non-recourse project financing (US$3.1 billion for Sarlux, ISAB, Api Energia).



Commercial IGCC plants

First of the large Italian IGCC plants, owned and operated by ISAB Energy (51% Erg Petroli and 49% Mission Energy), came on-line in 2000. It is located at the Erg refinery in Priolo, Sicily.

The multi-shaft combined cycle power block, net rated at 520 MW without deducting for gasification auxiliary loads such as the air separation unit, is built around two Ansaldo Siemens V94.2K gas turbines.

Sarlux, the second Italian plant rated at 550 MW, is said to be the largest IGCC plant in the world. It is located at the Saras Oil Refinery, on the island of Sardinia, which supplies the heavy residue feedstock for gasification.

Air Liquide provides oxygen and nitrogen to each of those facilities on an "over the fence" sales basis.

Sarlux started commercial syngas operation in January 2001. It was built by Snamprogetti, Turbotechnica (Nuovo Pignone) and GE Power Systems under ownership of a joint venture between Enron and Saras.

It contains three 184 MW STAG 109E GE/Nuovo Pignone single-shaft combined cycle units.

Output power is sold into the local grid, under a 20-year long term power purchase agreement with Enel.

The plant also supplies the Saras refinery with 200 tons per hour process steam and 1.4 million scf per hour of hydrogen feedstock.

The third plant, owned by Api Energia, is located at the Ancona refinery on the Adriatic coast and entered commercial operation in April 2001.

It was developed as a joint venture project by Anonima Petroli Italiana (51% stake), ABB (25%) and Texaco (24%), and is now 100% owned by Api.

The 280 MW combined cycle power block in this case is built around a syngas modified GT13E2 gas turbine.

Plant design features

Close examination of the ISAB and Sarlux plants reveals subtle design differences in plant configuration that were in large part dictated by plant owner and operations considerations.

Both plants use Texaco (now GE Energy) oxygen-blown quench gasification technology to convert heavy residual oil feedstock to syngas: two gasification trains operating at 70 bar for ISAB versus three, running at only 40 bar, for Sarlux.

Neither has a spare gasifier installed, so that gasifier capacity effectively matches combined cycle requirements. Each gas turbine is fed by a single gasifier. In both cases the gasification process takes place at around 1400°C (2552°F).

However, they do have different sulfur removal systems: a "hybrid" MDEA-Dow Chemical system for ISAB and a "physical" Selexol-UOP system at Sarlux.

Perhaps this has something to do with the different sulfur recovery and tail-gas treatment (H2S to elemental sulfur) methods used at the two plants.

At the ISAB plant the tail gas is treated and incinerated, while at Sarlux it is compressed and recycled back to the Selexol unit. Cleaned syngas in both cases contains about 30 ppm sulfur.

In the case of the ISAB plant, the clean syngas is sent to an expander, where the higher pressure is recovered to produce about 5 MW of additional power.

Syngas treatment

At Sarlux the syngas goes to a UOP hydrogen removal and recovery unit which includes a membrane section and a pressure swing absorption (PSA) section to produce pure hydrogen (over 99% vol) for use within the refinery.

Both plants "moisturize" the syngas in saturator units so that it ends up containing on the order of 35-40% by volume water vapor, before being forwarded to the gas turbines.

This steam dilution has the effect of lowering combustion flame temperature, and thereby NOx production, and also adds a bit of a power boost for the gas turbines.

The fuel gas delivered at around 400°F temperature has an LHV heating value on the order of 165 Btu/scf.

Combined cycle modules

At ISAB the combined cycle is a 2 x 1 design comprised of two Ansaldo Siemens V94.2K gas turbine generators, two HRSGs with duct firing capability, and one condensing steam turbine generator.

For Sarlux, there are three separate 1 x 1 single-shaft GE STAG 109E units, each including one Frame 9001E gas turbine, double-ended generator, condensing steam turbine and HRSG.

Although details are not available from Snamprogetti, they report that the EPC contract values for the two plants "do not differ substantially" so they can be assumed to cost about the same on a $ per kW basis.

Similar start-up hiccups

Also, according to Snamprogetti engineers, the ISAB and Sarlux IGCC plants went through similar commissioning, startup and performance improvement experiences.

There were no problems or delays during initial startup testing and commissioning on backup fuel oil systems. However, integrated IGCC commissioning and startup testing took 10-12 months in each case.

Once in service, both plants also experienced significant operating problems that were complicated by the number of technologies and individual systems involved. These were the first large scale 500 MW-plus IGCC projects commissioned.

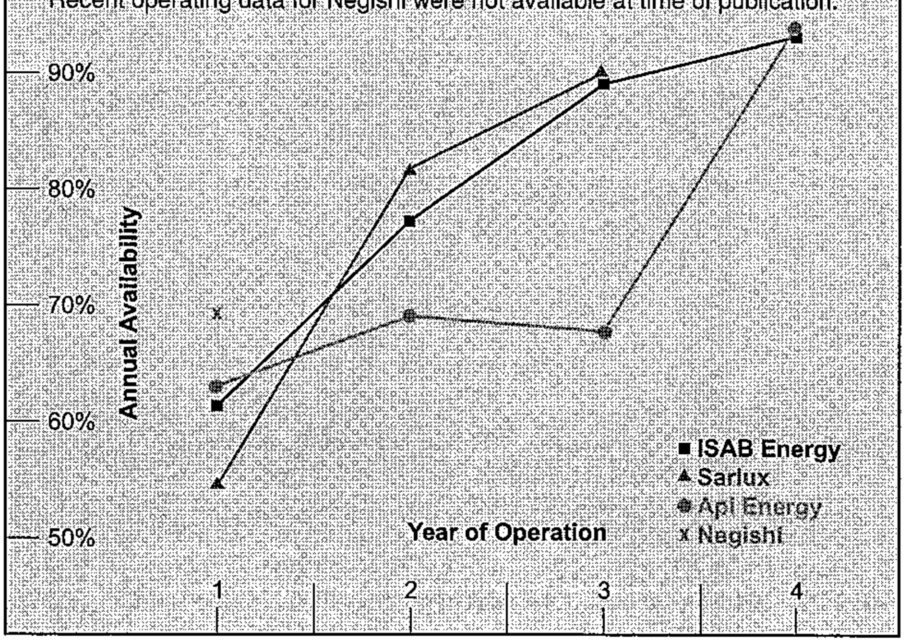
During the first year, after the start of commercial operations, the annual capacity factor on syngas at ISAB was down around 61%, and only around 55% for Sarlux.

Even taking into account plant operation on backup fuel oil, the annual capacity factor came to only 75% and 79% respectively that first year.

ISAB operating issues

Problems at ISAB reportedly had to do with severe corrosion in soot water and gray water circuits, syngas expander reliability, gasifier refractory hot spots, and gas turbine combustor

Commercial IGCC availability. ISAB Energy went from 61% to 93% in four years, Sarlux from 55% to 90% in three years and Api Energy from 63% to 94% in four years. Nippon Refining plant in Negishi operated at 69% availability on syngas in its first year of operation. Excludes operation on backup fuel. Recent operating data for Negishi were not available at time of publication.



Source: EPRI, Snamprogetti / Eni, ERG

deposits.

Project engineers note that the asphaltines design feedstock was the heaviest oil feed to be gasified at that time.

Gas turbine deposits, primarily of nickel alloy, were apparently caused by the reaction of CO in the fuel with nickel in combustion system components.

Detailed investigation traced the cause of the deposition to the disassociation of a single contaminant, Nickel Carbonyl (Ni CO4).

There was also an issue with higher than expected ratio of H2 to CO in the syngas, especially with light feedstock, that caused combustion problems.

Initially, Ansaldo and Siemens treated this as an out-of-specs fuel condition and restricted the use of syngas in the gas turbines.

Adjusting gasifier operating temperature and reducing the steam-to-oil feed ratio in the gasifiers solved the problem, but compromised gasifier performance.

Ultimately, Ansaldo and Siemens performed the necessary combustion testing to demonstrate the capability to handle the higher syngas hydrogen levels, resolving the issue and allowing the gasifiers to run at their design operating conditions.

Sarlux operating issues

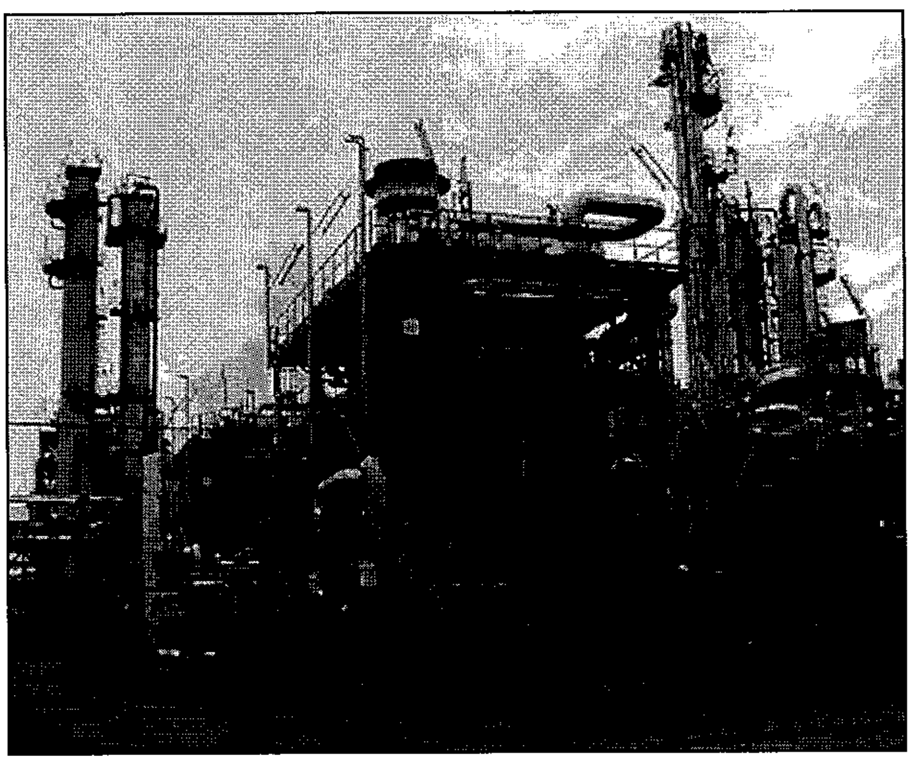
The first year of operation was marked by a persistent problem of soot carryover in the syngas, especially during plant transients, such as load changes during operation.

This was resolved by modifying gasifier and syngas scrubber operating procedures.

There was also a carryover issue due to the recycling of a small amount of water containing Selexol solvent. Eliminating the recycle greatly improved operation, say project engineers.

Another early problem at Sarlux involved severe damage to the hydrogen removal and recovery membrane system due to contact with some minor amount of Selexol carryover.

This was solved by adding new high-efficiency coalescing separators in lieu of the conventional demisters used in the original design.



280 MW Api Energy IGCC plant. Two parallel train GE gasifiers produce syngas for a single GT13E2A gas turbine. This is a view of the sulfur recovery units (center), sour water stripping towers (right) and the Selexol regenerator and absorber.

Steady improvement gains

With resolution of initial equipment problems, and improved operating procedures, IGCC plant availability showed steady improvement.

During 2004, with four years of commercial operation behind it, the ISAB plant enjoyed around 93% capacity factor on syngas according to a report issued by one of the plant owners.

This was up from 89% during the third year of commercial operation, and 77% the year before that.

The Sarlux plant also witnessed a dramatic improvement within the frist three years of operation.

Capacity factor on syngas improved to 90%, climbing up from a lowly 55% the first year.

Adding operating time on backup fuel brings this figure to a very respectable 88%.

Although detailed data are lacking, current operation of the Sarlux plant is said to be quite satisfactory.

Api Energy design

The 280 MW Api Energia plant at Falconara Marittima differs from the other two IGCC plants in that it has two gasifiers feeding one gas turbine.

It features two parallel trains of Texaco gasifiers (now GE Energy) producing syngas for a single ABB GT13E2A gas turbine combined cycle unit.

Like the arrangement at ISAB, a syngas expander is used to recover excess pressure energy upstream of the gas turbine fuel control valve.

But, unlike the earlier Italian plants where the syngas is saturated by steam prior to combustion, compressed nitrogen from the air separation unit (ASU) is injected into the syngas for a 50% dilution for NOx control.

Another unique feature is the addition of an auxiliary boiler to supply plant steam in the event of gas turbine outage.

During normal operating conditions, the auxiliary boiler is kept at minimum load and the steam produced is recirculated into the steam and water cycle.

First-year jitters

Like the other plants, equipment and operating problems at Api seriously detracted from plant availability during its initial commercial service.

After about a year the plant owners awarded a contract to Foster Wheeler Italiania, the original EPC contractor, to resolve the problems and bring the plant up to design performance.

According to project engineers assigned that task, IGCC plant availability during the first two years of operation was in the range of 70% and caused investor concern.

It also resulted in high maintenance costs and created problems with plant neighbors due to excessive flaring and frequent steam safety valve discharge noise during plant upsets.

Improvement targets

The main problem areas for the Foster Wheeler "availability improvement" project initiated in 2002 had to do with low safety system effectiveness; low instrumentation reliability; metallurgical inadequacies; equipment performance limitations.

A reliability, availability and maintainability (RAM) study was conducted at the outset to provide a roadmap for improvements.

The study showed that the theoretical average equivalent availability of the plant operating on syngas was 87% -- taking into account the Falconara plant configuration and utilizing an industry RAM database relevant to

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

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

Source: Luke O'Keefe, Burns & Roe

operating IGCC plants.

Plant owners and the project engineers took this figure as their reference target in pursuit of the multi-year availability improvement project.

As a result, a plant upgrade program was initiated, with modifications to be implemented during each of the three annual planned maintenance outages during 2002, 2003, and 2004.

Safety first

Among the plant-wide studies performed was a Safety Integrity Level study in accordance with international standards for more than 300 safety instrumentation system functions.

All of the specified modifications related to safety were implemented along with a number of corrective measures that were identified for overall IGCC plant design and operation.

Modifications related to plant reliability and performance were subjected to rigorous cost-benefit analyses and prioritized.

A series of instrumentation and control system reliability improvement measures included automated flow regulators to replace simple orifices, increased control loop redundancy, and high-performance CPUs and operator station controllers to handle heavy software loads.

Steam cycle

Particular attention was given to the auxiliary boiler system to insure its backup supply of steam to the refinery and to the gasifiers in the event of a combined cycle trip.

Basically, the burner management system was simplified and made more flexible to improve its reliability.

Several measures were taken to improve the reliability of the steam and water cycle, according to the project engineers, the most important of which included duplication of de-superheating stations to allow on-line maintenance.

An automatically actuated control valve was also installed at the auxiliary boiler outlet to replace the original on-off valve.

This was to allow a smooth and reliable release of high pressure steam to the atmosphere in the event of a combined cycle plant or steam turbine trip.

Proposed 500 MW pet-coke refinery project in the U.S.

Given Europe's example of what can (and should) be done with refinery residuals, and the proven benefits of IGCC in a refinery application, there is growing interest in the U.S. for similar plants.

With new federal incentives for pet-coke IGCC plants now in place under the Energy Policy Act of 2005, plans have been announced for at least one plant and more can be expected to follow.

BP and Edison Mission Group (affiliate of Mission International) recently unveiled plans for a 500 MW pet-coke IGCC plant to be located at the BP refinery near Carson, California, south of Los Angeles. Plant startup date set for 2011.

This first-of-a-kind commercial-scale project will carry the IGCC theme one step further by featuring CO_2 separation and sequestration in the form of injection into deep reservoirs for enhanced oil recovery.

Combined cycle power unit will be fired with near-pure hydrogen that will remain from the syngas after it is stripped of about 90% of the CO_2 before the gas is fed to the modified gas turbine combustion system.

No information has been disclosed regarding the gasification or combined cycle suppliers. A final decision to go ahead with the proposed project is not expected until 2008.

Materials upgrades

Reliability studies of the Falconara plant placed focus on two systems where materials upgrades were indicated, i.e. the gray water system and the oxygen system.

In the gray water system, corrosion and erosion phenomena were evident in carbon steel piping, equipment and control valves.

Metallurgical studies indicated that this was due to the effect of acidic conditions in the presence of solids (soot, ash) in these components. However, initial measures taken to neutralize the acids did not solve the problem.

Subsequent change to stainless steel for parts where the corrosion and erosion damage was most severe achieved the desired result.

The focus on the oxygen system came after a plant shutdown due to loss of oxygen, and the owner gave high priority to finding a solution to assure higher safety and reliability levels.

As a result, the original stainless steel material in some portions of the system handling high velocity oxygen was replaced with Monel 400 material.

Non-materials modifications to the oxygen system included adding new lines and isolation valves to improve system maintainability.

It involved replacing manual valves with multi-stage restriction orifices in each oxygen vent line, installing new automatic valves, adding instrumentation and controls for startup and shutdown of the gasifiers.

Critical equipment

One major equipment upgrade to achieve targeted RAM performance was to replace a 23 MW electric motor drive for the main ASU air compressor with a more powerful unit.

The original motor had been repaired after being severely damaged when a cooling water leak caused an insulation failure.

In the eyes of the owners and inspection engineers, the incident and subsequent repair left this critical plant item unreliable.

The replacement compressor motor is rated at 24.5 MW, providing some margin over the original design.

It also has many electrical and mechanical design upgrade features such as titanium water-to-air coolers that are corrosion resistant to the seawater coolant.

On top of this, the cooling system was redesigned in such a way as to preclude seawater coming in contact with the windings.

It also is equipped with an on-line rotor telemetry monitoring system to allow for thorough remote supervision of all motor operating parameters.

Seaside air intake

Apparently the seaside location of the plant was not fully taken into account in specifying the gas turbine inlet air filter to protect against salt air and water ingestion. The original filter lacked any special provisions for water removal.

Since the face of the gas turbine intake is only about 50 feet from the shoreline, and the site is subject to frequent winter storms and rough sea conditions, salt water droplet carry-over into the gas turbine compressor was quite predictable.

In addition, this environment caused the particulate-capturing ability of the filter media to deteriorate over a short time.

Considering the availability target set for the plant, the owners saw this problem as serious enough to justify replacing the original gas turbine inlet filter with one specifically designed for the plant site conditions.

Design requirements for the new filter included inlet flow face velocity not to exceed 2.7 meters per second, high droplet removal efficiency using a stainless steel demister section, a two-stage coalescer section, a bag-type pre-filter, and a last stage "fine" filter.

The new filter was installed and commissioned during the scheduled combined cycle outage at the end of 2003, and its performance has been reported as being highly satisfactory.

Lessons learned

Results of the three-year availability improvement project carried out at the Api plant are impressive and were mainly implemented during the first gas turbine major overhaul late in 2003.

After averaging only about 67% during the first three years of commercial operation, plant availability (as measured by percentage of operating hours relative to 8760 hours per year) jumped to 94% in 2004.

This performance substantially exceeded the 87% target and is indicative of the potential improvement possible in utilization and profitability.

The longer-term results, factoring in planned outages and aging of the new and modified equipment, will likely be more in line with expectations.

This experience with commercial-scale plants in Europe demonstrates that IGCC plants can operate at capacity factors comparable to, if not better than, conventional coal plants. ■

Select IGCC and Gasification Project Financings. These IGCC and gasification projects were privately project financed, and in several cases refinanced, with non-recourse arrangements based on project quality and pro forma.

Project	Sponsors	Financial Close	Feed	Products	Financing
Puertollano, Spain	EDF, Endesa, Iberdrola	1994	coal/coke	300 MW	non-recourse
ISAB Energy, Italy	ISAB, Mission Energy	March 1996 (refinanced)	asphalt	520 MW	non-recourse
Api Energia, Italy	Api, ABB	May 1996 (refinanced)	visbreaker tar	280 MW and steam	non-recourse
Sarlux, Italy	Saras, Enron	Nov 1996 (refinanced)	visbreaker tar	545 MW steam + H2	non-recourse
El Dorado, Kansas, US	Texaco	1996	petroleum coke	42 MW and steam	operating lease
Motiva, Delaware US	Star Enterprise	August 1997	petroleum coke	160 MW and steam	bonds
Coffeyville, Kansas US	Farmland, Texaco	Dec 1997	petroleum coke	1,000 tpd ammonia	bonds
Singapore Syngas	Texaco, Messer	Dec 2000	heavy oil	54 mmcfd syngas	non-recourse

Source: Luke O'Keefe, Burns & Roe

SITE ALTITUDE & AMBIENT TEMPERATURE EFFECTS ON IGCC

- The Gas Turbine Compressor Section is a "Constant Volumetric Flow" machine, while the output of the Turbine Section depends on the mass flow of air, fuel, and other diluents (nitrogen, steam. Water, etc), added to the gas stream between the compressor discharge and turbine entrance.

- The density of the airflow and, hence, the turbine mass flow varies inversely with ambient temperature and site altitude..

- The turbine output per unit of mass flow is typically twice that of the compressor work required to compress the air, because of the higher temperature of the gas. The difference between turbine output and compressor work is net output to the electric generator.

- The turbine is normally output and environmental performance rated for ISO condition – a 59°F ambient temperature at a sea level site. However, its shaft torque capacity is usually based on 0°F sea level conditions, 13-15% higher than ISO-rated output, with significant extra safety margin for generator ground fault dynamic loads.

- The turbine is normally designed for natural gas or oil fuels, where the fuel mass flow is on the order of 2% of the compressor air mass flow. In synfuel operation, the flow of fuel is 4-5 times that of natural gas and the nitrogen or steam diluent required to meet NO_x environmental limits equals or exceeds the fuel flow, for a total of 16-20% of compressor air flow.

- The extra mass flow through the Heat Recovery Steam Generator also increase steam turbine output by a similar percentage. Hence the IGCC system at the same site altitude and ambient temperature will have a potential electrical output that is 27-35% greater than that for a NGCC, even considering the firing temperature reductions required by the high gas stream moisture content and its effect on heat transfer.

- At 5000 feet site elevation the air density is down by 13%, which reduces the IGCC generator output by approximately 13% -- still 6-14% greater than an ISO rated NGCC.. There is a second order effect on parasitic power for the Air Separation Unit; meaning the IGCC would be down another 0.5-1% in net electrical output.

- The unit can be "flat-rated" at Turbine Shaft Torque limits over the 0-100°F ambient temperature range by (1.) injecting more nitrogen, steam, or water between the compressor discharge and turbine inlet (2.) cooling and possibly turbo-charging the compressor inlet air, or (3) duct burning in the inlet to the HRSG to increase steam turbine output.

- All of the output enhancements, which would be used on high elevation IGCC units at temperatures above 30-50°F, have lower incremental costs than the base plant or even peaking natural gas capacity, have small impacts on cycle efficincy, and provide valuable hot day generation capacity. **Altitude and Ambient Temperature effects on IGCC units are real, but are manageable.at reasonable cost and efficiency impact using state-of-the art methods that have been demonstrated at commercial scale**

5.0 Best Available Control Technology Analysis

The proposed IGCC project is classified as a new major source of regulated emissions under the Prevention of Significant Deterioration (PSD) program. An analysis of the Best Available Control Technology (BACT) is required for sources with potential emissions greater than the PSD established significance thresholds. The BACT analysis evaluates the technical feasibility and cost-effectiveness of emission control options to determine the applicable control technology and emission limits. The following BACT analysis will result in emission control levels that are equivalent to or more stringent than those that would be determined to be best available technology (BAT) per Ohio EPA regulations (OAC 3745-31-05). The table below summarizes the PSD pollutants requiring a BACT analysis for the proposed project.

Table 5-1: Potential Project Emissions and PSD Significance Thresholds

PSD Pollutant	PSD Significance Threshold (tpy)	Estimated Facility Potential to Emit (tpy)	BACT Applicable
Carbon Monoxide (CO)	100	944	Yes
Nitrogen Oxides (NO_x)	40	1,562	Yes
Sulfur Dioxide (SO_2)	40	586	Yes
Particulate Matter $\leq$10 microns (PM_{10})	15	204 (PM_{10} - filterable)	Yes
Volatile Organic Compounds (VOC)	40	83	Yes
Sulfuric Acid Mist (H_2SO_4)	7	98	Yes
Lead (Pb)	0.6	<0.04	No

5.1 BACT Analysis Summary

A BACT analysis was performed for the proposed combustion turbines, sulfur recovery process, auxiliary boiler, cooling tower, and the material handling system. A summary of the proposed control technologies and emission limits resulting from the analysis is provided below. The averaging periods are equivalent to the periods established by the applicable NSPS. In absence of an applicable NSPS, the proposed averaging periods represent the minimum averaging period associated with the national ambient air quality standards or historic averaging periods represented in previous determinations.

Table 5.2: IGCC Combustion Turbine BACT Analysis Summary

PSD Pollutant	Proposed BACT	Proposed BACT Emission Limits (emission limits are per combustion turbine)
NO_x	Diluent Injection to: 15 ppm NO_x (100% syngas) 25 ppm NO_x (100% natural gas)	NO_x Limit (100% syngas): 170.3 lb/hr (30-day ave) NO_x Limit (100% natural gas): 188.9 lb/hr (30-day ave)
SO_2 H_2SO_4	AGR designed to reduce syngas sulfur to 40 ppm (as H_2S)	SO_2 Limit: 51.3 lb/hr (30-day ave) H_2SO_4 Limit: 11.3 lb/hr (30-day ave)
CO	Good Combustion Practices	CO Limit: 93.3 lb/hr (1-hr ave)
VOC	Good Combustion Practices Use of Clean Fuels	VOC Limit: 3.2 lb/hr (8-hr ave)
Particulate Emissions	Good Combustion Practices Use of Clean Fuels	Particulate Limit (PM_{10} - filterable): 18 lb/hr (24-hr ave)

Table 5.3: IGCC Sulfur Recovery System BACT Analysis Summary

Proposed BACT	Proposed BACT Emission Limits		
Flare: Natural Gas Pilot Smokeless Flare Design Flame Detection System Auto-Ignition System Maximum Gas Velocity Thermal Oxidizer Natural Gas Pilot Minimum Operating Temperature Low NO_x Burners Optimized IGCC Process Design Low Pressure Absorber System Minimize frequency & duration of control by flare & thermal oxidizer.	**PSD Pollutant**	**Flare**	**Thermal Oxidizer**
	SO_2	684.9 lb/hr (3-hour average)	150.9 lb/hr (3-hour average)
	NO_x	59.4 lb/hr (24-hour average)	8.7 lb/hr (24-hour average)
	CO	312.9 lb/hr (1-hour average)	7.4 lb/hr (1-hour average)
	VOC	0.2 lb/hr (8-hour average)	0.5 lb/hr (8-hour average)
	Particulate Emissions	0.2 lb/hr (PM_{10} - filterable) (24-hour average)	0.7 lb/hr (PM_{10} - filterable) (24-hour average)

Table 5.4: Auxiliary Boiler BACT Analysis Summary

PSD Pollutant	Proposed BACT	Proposed BACT Emission Limits	
NO_x	Low NOx Burners Flue Gas Recirculation	NO_x Limit:	0.05 lb/mmBTU (30-day ave)
SO_2	Low Sulfur Fuel (natural gas)	SO_2 Limit:	0.0007 lb/mmBTU (30-day ave)
CO, VOC, Particulate Emissions	Good Combustion Practices Use of Clean Fuels (natural gas)	CO Limit: VOC Limit PE (PM_{10} - filterable):	0.08 lb/mmBTU (1-hr ave) 0.005 lb/mmBTU (8-hr ave) 0.0075 lb/mmBTU (24-hr ave)

Table 5.5: Cooling Tower BACT Analysis Summary

PSD Pollutant	Proposed BACT	Proposed BACT Limits
Particulate Emissions	Drift Elimination System	Particulate (PM_{10} - filterable): 6.38 lb/hr (24-hr ave)

Table 5.6: Material Handling BACT Analysis Summary

PSD Pollutant	Proposed BACT	Proposed BACT Limits
Particulate Emissions	Forced Air Dust Control Systems Dust Suppression Systems	Periodic observations of fugitive dust sources and implementation of corrective actions (as necessary). Maintain records of inspections not performed or corrective actions not implemented (as necessary).

5.2 BACT Review Process

A BACT related emission limit is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs"* [40 CFR 52.21(b)(12)]

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all potentially applicable emission control technologies according to control effectiveness. Evaluation begins with the top or most stringent emission control alternative. If the most stringent control technology is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and the next most stringent control technology is similarly evaluated. This process continues until the BACT option under consideration cannot be eliminated. The top control alternative not eliminated is determined to be BACT. This process involves the following five steps[1]:

- Step 1: Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Step 2: Eliminate all technically infeasible control technologies;
- Step 3: Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;
- Step 4: Evaluate most effective controls and document results; and
- Step 5: Select BACT, which will be the most effective practical option not rejected based on economic, environmental, and/or energy impacts.

Formal use of these steps is not always necessary. However, the BACT requirements have consistently been interpreted to contain two core components that must be met in any determination. First, the BACT analysis must consider the most stringent available technologies (those with the potential to provide the maximum reductions). Second, a determination to utilize a technology with a lesser potential control efficiency must be supported by an objective analysis of the associated energy, environmental, and economic impacts. Additionally, the minimum control efficiency evaluated in the BACT analysis must at least achieve emission rates equivalent to applicable New Source Performance Standards.

The process of identifying potential control technologies involves researching many resources, including a review of existing and historical technologies that have been proposed or implemented for other projects and a survey of available literature. Evaluating the applicability of each control option entails an assessment of feasibility and cost-effectiveness. This process determines the potential applicability of a control technology by considering its commercial availability (as evidenced by past or expected near-term deployment on the same or similar types of emission units). An available technology is one that is deemed commercially available because it has progressed through the following development steps: concept stage; research & patenting; bench scale/laboratory testing; pilot scale testing; licensing & commercial demonstration; and commercial sales.

The evaluation process also considers the project specific physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit because of differences in the physical and chemical characteristics of gas streams to be controlled.

The following BACT analysis for the proposed IGCC facility was conducted in a manner consistent with the top-down approach. As part of this analysis, control options for potential reductions were identified by researching the EPA RACT/BACT/LAER Clearinghouse database, by drawing upon engineering and IGCC permitting experience, and by surveying available literature. Potential controls identified were then evaluated as necessary on a technical, economic, environmental, and energy basis.

[1] "New Source Review Workshop Manual", DRAFT October 1990, EPA Office of Air Quality Planning and Standards

5.3 Existing and Permitted IGCC Facilities

Air permitting information for the following IGCC projects, which have been issued a final air permit, was reviewed and used in performing the BACT analysis for the proposed AEP IGCC project:

- SG Solutions - Wabash River Generating Station; Indiana (operating);
- Tampa Electric Company - Polk Power Station; Florida (operating);
- WE Energies - Elm Road Generating Station; Wisconsin (permitted/not constructed);
- Global Energy, Inc. - Kentucky Pioneer Energy LLC; Kentucky (permitted/not constructed);
- Global Energy, Inc. - Lima Energy Company; Ohio (permitted/not constructed).

These IGCC projects represent a variety of process designs that not only incorporate different technologies for gasification and syngas cleanup, but also utilize different types and qualities of solid fuels. A variety of different combustion turbine models are also represented. In addition, the size and scope of these projects vary. All of this is indicative of the ongoing development of IGCC technologies. The proposed AEP project further develops and optimizes many of the design concepts proposed and utilized by these permitted projects, and represents a significant first-of-a-kind commercially acceptable scale-up of the IGCC process.

Because of the design and operational differences between permitted IGCC projects, any comparison of emission rates or control technologies can only qualitatively be performed. The comparison is further complicated since only two of the permitted IGCC facilities are in operation, while the others have not been constructed and their emission limits have not yet been demonstrated. In addition, the emission limits are often expressed in different units among permits, which impairs direct comparison between projects.

A general qualitative comparison of permitted IGCC projects and the proposed AEP IGCC project is provided below, which summarizes the estimated combustion turbine emission limits for each project. The emission limits have been estimated based on permit limits and an estimated solid-fuel based gasifier heat input. Nominal preliminary estimates were derived for the proposed AEP project combustion turbines when using syngas at full load. In general, the potential emissions for the proposed AEP project are lower than those for other permitted IGCC projects of varying sizes, technologies, and fuel characteristics.

Table 5.7: Estimated Permitted IGCC Combustion Turbine Emission Rates

Location	Estimated Gasifier Heat Input (MMBtu/hr)	Estimated CO Rate (lb/MMBtu)	Estimated NO_x Rate (lb/MMBtu)	Estimated SO_2 Rate (lb/MMBtu)	*Estimated PE Rate (lb/MMBtu)	Estimated VOC Rate (lb/MMBtu)
Wabash River (operating)	2,356	0.036	0.087	0.126	0.005	0.001
Polk Power Station (operating)	2,191	0.045	0.101	0.170	0.008	0.001
Kentucky Pioneer (not constructed)	4,413	0.026	0.059	0.026	0.009	0.004
Lima Energy (not constructed)	4,413	0.035	0.067	0.022	0.008	0.007
We Energies (not constructed)	5,424	0.024	0.059	0.023	0.008	0.003
AEP IGCC Project (nominal projections)	6,000	0.031	0.057	0.017	0.006	0.001

*The particulate emission rates for permitted projects do not specify the type of particulate represented by the limit.
PE estimates for AEP project represent PM_{10} - filterable.

5.4 Combustion Turbine Control Technology Review

The following is the BACT analysis for the proposed combustion turbines. Each of the two proposed combustion turbines will be a GE 7FB model turbine with a nominal capacity of 232 MW. The GE 7FB is a new turbine model designed to optimally utilize syngas and natural gas.

5.4.1 Nitrogen Oxides BACT Analysis for the Combustion Turbines

NO_x is formed during combustion primarily by the reaction of combustion air nitrogen and oxygen within the high temperature combustion zone (thermal NO_x), or by the oxidation of nitrogen in the fuel (fuel NO_x). Because syngas contains negligible amounts of fuel-bound nitrogen, essentially all combustion turbine NO_x emissions originate as thermal NO_x.

The rate of thermal NO_x formation in the combustion turbines is primarily a function of the fuel residence time, availability of oxygen, and peak flame temperature. Several NO_x control technologies are available to reduce the impacts of these variables during the combustion process, including diluent injection and dry low NO_x burner technology. Post-combustion control technologies have also been used in some processes to remove NO_x from the exhaust gas stream.

➢ ***Identify Control Technologies***

The following NO_x control technologies were evaluated for the proposed IGCC combustion turbines:

Combustion Process Controls

- Diluent Injection
- Dry Low NO_x burners
- Flue Gas Recirculation

Post Combustion Controls

- SCONOx
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

➢ ***Evaluate Technical Feasibility***

Diluent Injection

Higher combustion temperatures may increase thermodynamic efficiency, but may also increase the formation of thermal NO_x. A diluent, such as steam or nitrogen, can be added to the syngas to effectively lower the combustion temperature and formation of thermal NO_x. Diluent injection has been determined as BACT for all currently operating IGCC facilities, and has been demonstrated to achieve NO_x emission rates of 15 ppmvd (at 15% O_2) when firing 100% syngas fuel. It is expected that diluent injection will achieve comparable or more efficient NO_x reductions with the proposed combustion turbines. Because the combustion characteristics of natural gas differ from syngas, the best performance achievable is 25 ppmvd NO_x when using natural gas. Diluent injection also increases the mass flow through the combustion turbine for greater power output. In summary, diluent injection is a technically feasible control technology for the proposed combustion turbines.

Dry Low NO_x Burners

Dry Low-NO_x (DLN) burner technology has successfully been demonstrated to reduce thermal NO_x formation from combustion turbines utilizing natural gas. This technology utilizes a burner design that controls the stoichiometry and temperature of combustion by regulating the distribution and mixing of fuel and air, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions.

Available DLN burner technologies for combustion turbines are designed for natural gas (methane-based) fuels, but are not applicable to combustion turbines utilizing syngas (hydrogen/CO-based), which has a different heating value, gas composition, and flammability characteristics. Research is ongoing to develop DLN technologies for syngas-fueled combustion turbines, but no designs are currently available. Therefore, DLN burner technology is not technically feasible for IGCC due to potential explosion hazards in the combustion section associated with the high content of hydrogen in the syngas.

Flue Gas Recirculation

Flue gas recirculation is being researched by combustion turbine manufactures, but is not currently an available control technology. While the technology may be a future option to reduce NO_x emissions, significant development work is required to complete maturation and integration of the concept into a power plant system, including validating all emissions characteristics and overall plant performance and operability. Additionally, current research efforts have focused on pre-mixed natural gas combustion, and results would need to be expanded to assess syngas applications. Thus, flue gas recirculation is not technically feasible for the proposed combustion turbines.

$SCONO_x$

$SCONO_x$ is a control technology that utilizes a single catalyst to reduce CO, VOC, and NO_x emissions. All installations of the technology have been on small natural gas facilities, and have experienced performance issues. $SCONO_x$ has not been applied to large-scale natural gas combustion turbines, which creates concerns regarding the timing, feasibility, and cost-effectiveness of necessary design improvements. $SCONO_x$ has also not been applied to syngas or exhaust streams containing sulfur in concentrations similar to the proposed project, which creates additional concerns regarding potential catalyst fouling. Therefore, $SCONO_x$ is not technically feasible.

Selective Catalytic Reduction (SCR)

SCR technology has never been attempted on an IGCC plant utilizing coal-derived syngas. BACT analyses for previously permitted IGCC plants have determined SCR is not technically feasible due to concerns regarding catalyst performance and potential operational impacts to downstream equipment. Several analyses noted the unavailability of meaningful performance guarantees from SCR suppliers. In other cases, the application of SCR to the IGCC process was not deemed cost effective due to increased operation & maintenance costs and the costs associated with reducing syngas sulfur to levels that are assumed to be adequate to minimize operational impacts.

AEP's initial evaluation of the application of SCR to IGCC indicates that the uncertainty regarding technical feasibility persists. In discussions with one SCR supplier, the vendor stated that commercial guarantees on catalyst performance and lifespan in a coal-derived syngas would be difficult to obtain. The supplier noted that a research and development (R&D) program would first be needed to address the uncertainties associated with the remaining technical feasibility issues. Without results from such a program, the value of any SCR performance guarantee, if available, would be minimal.

On July 7, 2006, USEPA released a technical report, titled *The Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies,* which includes a discussion regarding the application of SCR to IGCC. Of note, the report acknowledges the differences in applying SCR to IGCC by stating:

> "....there are fundamental differences between natural gas and syngas-fired turbines that make the use of SCR with IGCC technologies more uncertain, and there are no installations at present at IGCC facilities firing coal."

The USEPA report identifies concerns regarding the impacts of ammonium sulfur compounds on the performance and maintenance requirements of downstream equipment. The impact to HRSG (heat recovery steam generator) performance is identified as a crucial question for applying an SCR to an IGCC process. Without an extensive R&D project to identify design characteristics required to alleviate feasibility concerns, it is difficult to evaluate the cost-effectiveness of applying an SCR to IGCC. However, the USEPA report used several assumptions to calculate a cost-effectiveness of $7,920 to $13,120 per ton of NO_x removed by applying an SCR to IGCC. Using these estimates, applying an SCR to IGCC would not be cost-effective even if feasibility issues are addressed.

In summary, no examples have been identified where an SCR has been applied or successfully demonstrated on a coal-derived IGCC unit. Performance uncertainties and unknown risks continue to pose significant technical feasibility concerns. Past AEP experience in applying first of a kind control technologies with inherent unknown operational and performance risks indicates that only through intensive R&D efforts and associated design optimizations can the risks be fully explored and addressed. In the absence of this kind of targeted R&D effort and the associated risk minimization that it would afford, AEP does not believe the technical feasibility issues have been sufficiently addressed to allow SCR to be selected as BACT, especially considering the significant operational and financial risks associated with developing the first generation of commercially acceptable IGCC plants. The basis for this position is summarized by the following:

- SCR has never been applied to IGCC plants utilizing coal-derived syngas.
- The SCR feasibility, cost, and risk issues to be evaluated as part of a BACT analysis are different between IGCC, pulverized coal, and natural gas combined cycle technologies.

- The performance of an SCR catalyst in a coal-derived syngas environment is unknown.
- The syngas sulfur concentrations necessary to alleviate SCR related concerns is unknown.
- The ability to obtain a meaningful performance guarantee is very limited, but is a key factor in determining the technical feasibility of SCR to IGCC.
- Only through an intensive R&D program can risks of applying an SCR to IGCC be explored and addressed.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_x control technology in which a reagent (ammonia or urea) is injected in the exhaust gas to react with NO_x to form nitrogen and water without the use of a catalyst. The success of this process in reducing NO_x emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas, which must occur in a very narrow high temperature range. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x, resulting in excess ammonia emissions. SNCR technology is occasionally used in conventional coal-fired heaters or boilers, but it has never been applied to natural gas combined cycle or IGCC units because no locations exist in the heat recovery steam generator with the optimal temperature and residence time that are necessary to accommodate the technology. Therefore, SNCR is not technically feasible.

➢ ***Rank Control Technologies***

Diluent injection is the only NO_x control technology determined to be technically feasible and commercially available for the proposed IGCC combustion turbines. Diluent injection has been selected as BACT for other permitted IGCC projects.

➢ ***Evaluate Control Options***

The use of diluent injection was identified as the only technically feasible NO_x control technology for the proposed IGCC combustion turbines. Diluent injection has been demonstrated to reduce NO_x emissions to 15 ppmvd (at 15% O_2) when firing syngas and 25 ppmvd (at 15% O_2) when firing natural gas. The associated potential full load NO_x emission rates are 170.3 lb/hr (100% syngas) and 188.9 lb/hr (100% natural gas). Assuming a nominal gross output from each combustion turbine of 232 MWh and 320 MWh from the common steam generator, the equivalent potential NO_x emission rate is approximately 0.21 lb/MWh (100% syngas) and 0.24 lb/MWh (100% natural gas). Both of these emission rates are significantly lower than the applicable NSPS Subpart Da limit of 1.0 lb/MWh.

➢ ***Select NO_x Control Technology***

Diluent injection using steam saturation and/or nitrogen has been selected as BACT for the proposed combustion turbines to reduce NO_x emissions to 15 ppm when using syngas and to 25 ppm when using natural gas. The proposed BACT NO_x limits are presented below for each combustion turbine. The averaging periods are equivalent to those set by NSPS Subpart Da.

- Proposed NO_x BACT Limit when burning (100% syngas): 170.3 lb/hr (30-day average)
- Proposed NO_x BACT Limit when burning (100% natural gas): 188.9 lb/hr (30-day average)

The NO_x BACT limits expressed for each combustion turbine are for normal operations. During startup and shutdown operations, NO_x emissions may be greater for certain periods due to unstable combustion associated with lower combustion turbine efficiencies and transitional periods between natural gas and syngas use. Potential emissions for startup and shutdown operations are evaluated as part of the modeling analysis presented in Section 7.

5.4.2 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis for the Combustion Turbines

The combustion turbines oxidize sulfur compounds in fuel primarily into sulfur dioxide (SO_2). A smaller fraction may form sulfur trioxide (SO_3), which can combine with the moisture in the exhaust to form sulfuric acid mist (H_2SO_4). Emissions can be controlled by limiting the fuel sulfur content or by removing SO_2 from the exhaust gas.

➢ ***Identify Control Technologies***
The following SO_2 control technologies were evaluated for the proposed IGCC combustion turbines:

Pre-Combustion Process Controls
- Chemical Absorption Acid Gas Removal
- Physical Absorption Acid Gas Removal

Post-Combustion Controls
- Flue Gas Desulfurization

➢ ***Evaluate Technical Feasibility***
Chemical and Physical Acid Gas Removal Systems
During the gasification process, sulfur in the feedstock converts primarily into hydrogen sulfide (H_2S), and will also convert into minor quantities of other sulfur species, such as carbonyl sulfide (COS). Commercially available acid gas removal (AGR) systems are capable of removing greater than 99% of the sulfur compounds from syngas. AGR systems are commonly used for gas sweetening processes of refinery fuel gas or tail gas treatment systems, and are typically coupled with processes that produce useful sulfur by-products. Because COS is not readily removed by AGR systems, a COS hydrolysis unit is often used upstream to convert COS to H_2S for greater total sulfur removal.

AGR systems can employ either chemical or physical absorption methods. Chemical absorption methods are amine-based systems that utilize solvents, such as methyldiethanolamine (MDEA), to bond with the H_2S in the syngas. A stripper column is then used to regenerate the solvent and produce an acid gas stream containing H_2S that can be processed into useful sulfur by-products. An MDEA AGR system has been determined as BACT for all operating and permitted IGCC facilities. The two operating IGCC facilities in the United States both use amine (MDEA) systems to reduce the syngas total sulfur concentration to 100 to 400 ppm[2].

Other types of AGR systems utilize physical absorption methods that employ a physical solvent to remove sulfur from gas streams, such as mixtures of dimethyl ethers of polyethylene glycol (Selexol) or methanol (Rectisol). These systems operate by absorbing H_2S under pressure into the solvent. Dissolved acid gases are removed resulting in a regenerated solvent for reuse and the production of an acid gas stream containing H_2S that can be processed into useful sulfur by-products. Physical absorption methods have historically been used to purify gas streams in the chemical processing and natural gas industries.

In summary, both chemical and physical acid gas removal systems are technically feasible control technologies.

Flue Gas Desulfurization
Flue gas desulfurization (FGD) is a post-combustion SO_2 control technology that reacts an alkaline with SO_2 in the exhaust gas. FGD systems are most commonly used by conventional pulverized coal units and can typically achieve a greater than 95% removal efficiency on new facilities. The FGD process results in a solid by-product that requires the installation of a significant number of ancillary support systems to accommodate treatment, handling, and disposal. FGD is more readily applied to high SO_2 concentration gas streams, such as those present with direct combustion coal units. No examples were identified where an FGD system has been applied to an IGCC facility or similar process. Therefore, FGD is not technically feasible for the proposed combustion turbines. Even if feasible to IGCC processes, FGD could not achieve the high removal efficiencies associated with AGR systems.

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[2] Tampa Electric Polk Power Station IGCC Project – Final Technical Report, August 2002; and Wabash River Coal Gasification Repowering Project – Final Technical Report, August 2000;

➢ ***Rank Control Technologies***

Both chemical and physical acid gas removal systems are technically feasible for IGCC processes and can achieve greater than 99% SO_2 removal efficiencies. Table 5.8 summarizes the potential control efficiencies associated with various syngas sulfur concentrations exiting the AGR system.

Table 5.8: AGR SO_2 Control Efficiencies

SO_2 Control Option	Syngas Sulfur (ppm)	Control Efficiency	[1]Nominal Estimate of Annual SO_2 Emissions (tons/year)	[1]Nominal Estimate of SO_2 Emissions Reduction (tons/year)
AGR to 20 ppm	20	99.85 %	234	154,891
AGR to 40 ppm	40	99.7 %	468	154,657
AGR to 100 ppm	100	99.25 %	1,170	153,955
NSPS Subpart Da (95% control option)	---	95 %	7,756	147,369
Uncontrolled	>10,000	---	155,125	---

[1] Nominal design values based on a two gasifier & two combustion turbine configuration

➢ ***Evaluate Control Options***

Economic Impacts

Physical and chemical absorption AGR systems can be designed for varying levels of control effectiveness resulting in greater capital and operating costs, along with increase operating risks for greater sulfur removal. Design removal efficiencies among the AGR technologies can overlap, but the capital and operating cost are significantly different. Evaluation of the economic impacts of various AGR design options is complicated by the proposed project being a first-of-a-kind scale-up of IGCC technology. Table 5.9 and Table 5.10 evaluate the cost-effectiveness of using different AGR technologies at various design syngas sulfur concentrations. Estimates are based on nominal design values, input from equipment vendors, and engineering experience.

Results of the analysis indicate the use of a physical absorption based AGR technologies will achieve greater sulfur removal rates more economically than chemical based AGR technologies. Based on this analysis, an AGR design to 40 ppm (expressed as H_2S) represents the best available cost-effective control technology. This level of control is significantly more stringent than the recently finalized New Source Performance Standard requirements and the sulfur removal rates being demonstrated by existing IGCC facilities operating in the United States.

Table 5.9: AGR Cost Estimates

Chemical Solvent based AGR - Cost Estimates

AGR Technology	Syngas Sulfur (ppm)	Sulfur Block Capital Cost (million $)	Annual Capital Recovery Cost (million $)	Operating Cost Steam & Electricity ($1,000/year)	Operating Cost AGR Solvent ($1,000/year)	Operating Cost COS Hydrolysis Catalyst ($1,000/year)	Operating Cost Maintenance ($1,000/year)	Total Annual Operating Cost (million $)	Total Annual Costs (million $)
Chemical Solvent AGR	60	111.4	12.2	4306.0	112.1	1020.8	2811.0	8.3	4314.3
Chemical Solvent AGR	80	97.4	10.7	3881.0	112.1	1020.8	2531.0	7.5	3888.5
Chemical Solvent AGR	100	89.2	9.8	3395.1	112.1	1020.8	2367.0	6.9	3402.0

Notes:
1. Total for two gasifiers & two combustion turbines configuration.
2. Nominal cost estimates for use in performing BACT Analysis only.
3. Annual capital recovery assumes a capital recovery factor of 0.1098 based on a 7% interest rate and 15-year equipment life.

Physical Solvent based AGR - Cost Estimates

AGR Technology	Syngas Sulfur (ppm)	Total Capital Investment (million $)	Annual Capital Recovery Cost (million $)	Operating Cost Steam & Electricity ($1,000/year)	Operating Cost AGR Solvent ($1,000/year)	Operating Cost COS Hydrolysis Catalyst ($1,000/year)	Operating Cost Maintenance ($1,000/year)	Total Annual Operating Cost (million $)	Total Annual Costs (million $)
Physical Solvent AGR	20	178.4	19.6	5311.0	328.8	1020.8	4299.0	11.0	5322.0
Physical Solvent AGR	40	161.0	17.7	4583.0	328.8	1020.8	3878.0	9.8	4592.8
Physical Solvent AGR	60	152.3	16.7	4189.0	328.8	1020.8	3683.8	9.2	4198.2
Physical Solvent AGR	80	146.1	16.0	3950.0	328.8	1020.8	3560.8	8.9	3958.9
Physical Solvent AGR	100	142.7	15.7	3780.0	328.8	1020.8	3493.8	8.6	3788.6

Notes:
1. Total for two gasifiers & two combustion turbines configuration.
2. Nominal cost estimates for use in performing BACT Analysis only.
3. Annual capital recovery assumes a capital recovery factor of 0.1098 based on a 7% interest rate and 15-year equipment life.

Table 5.10: AGR Cost Effectiveness Evaluation

Chemical Solvent based AGR - Cost Effectiveness Evaluation

AGR Technology	Syngas Sulfur (ppm)	Total Capital Investment (million $)	Annual Capital Recovery Cost (million $)	Total Annual Operating Cost (million $)	Total Annual Costs (million $)	Average Cost Effectiveness ($/ton)	Incremental SO_2 Reduction (tons/yr)	Incremental Cost Effectiveness ($/ton)
Chemical Solvent AGR	60	111.4	12.2	8.3	20.5	132.9	231	10,124
Chemical Solvent AGR	80	97.4	10.7	7.5	18.2	118.0	231	6,499
Chemical Solvent AGR	100	89.2	9.8	6.9	16.7	108.4	6,602	2,529

Notes:

1. Total for two gasifiers & two combustion turbines configuration.
2. Nominal cost estimates for use in performing BACT Analysis only.
3. Annual capital recovery assumes a capital recovery factor of 0.1098 based on a 7% interest rate and 15-year equipment life.

Physical Solvent based AGR - Cost Effectiveness Evaluation

AGR Technology	Syngas Sulfur (ppm)	Total Capital Investment (million $)	Annual Capital Recovery Cost (million $)	Total Annual Operating Cost (million $)	Total Annual Costs (million $)	Average Cost Effectiveness ($/ton)	Incremental SO_2 Reduction (tons/yr)	Incremental Cost Effectiveness ($/ton)
Physical Solvent AGR	20	178.4	19.6	11.0	30.6	197.5	231	13,474
Physical Solvent AGR	40	161.0	17.7	9.8	27.5	177.7	231	6,737
Physical Solvent AGR	60	152.3	16.7	9.2	25.9	167.9	231	4,249
Physical Solvent AGR	80	146.1	16.0	8.9	24.9	161.7	231	2,917
Physical Solvent AGR	100	142.7	15.7	8.6	24.3	157.6	6,602	3,676

Notes:

1. Total for two gasifiers & two combustion turbines configuration.
2. Nominal cost estimates for use in performing BACT Analysis only.
3. Annual capital recovery assumes a capital recovery factor of 0.1098 based on a 7% interest rate and 15-year equipment life.
4. Average cost effectiveness vs. nominal uncontrolled rate of 155,125 tpy.

Environmental Impacts

Each AGR design presented in Tables 5.9 and 5.10 reduces syngas sulfur concentrations by greater than 99%, and produces a secondary gas stream that can be processed into potentially useful sulfur by-products. The solvent used by each AGR system will be regenerated and reused. Any related water streams will be treated before discharge. Overall, no collateral environmental issues have been identified that would preclude any of the AGR design options from consideration as BACT for the proposed project.

➢ ***Select SO_2 Control Technology***

A physical absorption AGR system designed to reduce syngas sulfur concentrations to 40 ppm (expressed as H_2S) has been selected as BACT for SO_2 and H_2SO_4 emissions from the proposed combustion turbines. The proposed AGR system will reduce syngas sulfur content by greater than 99%.

The proposed BACT limits associated with a syngas sulfur content of 40 ppmvd (expressed as H_2S) are presented below for each combustion turbine. The averaging period for SO_2 is equivalent to that established by NSPS Subpart Da. The H_2SO_4 averaging period is proposed to parallel that for SO_2.

- Proposed SO_2 BACT Limit: 51.3 lb/hr (30-day average)
- Proposed H_2SO_4 BACT Limit: 11.3 lb/hr (30-day average)

The potential SO_2 and H_2SO_4 combustion turbine emission rates during startup and shutdown operations are less than or equal to the aforementioned BACT limits for normal operations. Potential emissions for startup and shutdown operations are provided in Section 4 and are evaluated as part of the air dispersion modeling analysis presented in Section 7.

5.4.3 Carbon Monoxide BACT Analysis for the Combustion Turbines

Carbon monoxide (CO) emissions are a result of incomplete combustion. CO emissions can be reduced by providing adequate fuel residence time and higher temperatures in the combustion zone to ensure complete combustion. However, these same control factors can increase NO_x emissions. Conversely, lower NO_x emission rates achieved through flame temperature control (by diluent injection) can increase CO emissions. The design strategy is to optimize the flame temperature to lower potential NO_x emissions, while minimizing the impact to potential CO emissions. The combustion turbines for the proposed project will be a GE 7FB model, which is a new design to optimally consume syngas and natural gas. Post-combustion control technologies have also been used to reduce CO emissions in some processes.

➢ ***Identify Control Technologies***

The following CO control technologies were evaluated for the proposed combustion turbines:

<u>Combustion Process Controls</u>

- Good Combustion Practices

<u>Post-Combustion Controls</u>

- $SCONO_x$
- Oxidation Catalyst

➢ ***Evaluate Technical Feasibility***

<u>Good Combustion Practices</u>

Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. This technology has been determined to be BACT for CO emissions in other IGCC permits.

<u>SCONOx</u>

The $SCONO_x$ system was evaluated in the NO_x BACT analysis, and determined to be not technically feasible.

<u>Oxidation Catalysts</u>

Catalytic oxidation is a post-combustion control technology that utilizes a catalyst to oxidize CO into CO_2. Trace constituents in the combustion exhaust can create significant concerns regarding the fouling and subsequent reduced performance of the catalyst. Because of these concerns, the use of oxidation catalysts has been limited to processes combusting natural gas. Oxidation catalysts have never been applied to coal-based IGCC processes and pose similar operational and financial risks to those associated with SCR as described in the NO_x BACT analysis, including increased formation of SO_3. Thus, an oxidation catalyst system is not technically feasible.

➢ ***Rank Control Technologies***

Good combustion practice is the only technically feasible CO control technology identified.

➢ ***Evaluate Control Options***

Good combustion practice is the only feasible control technology identified, and has been selected as BACT for other IGCC projects.

➢ ***Select CO Control Technology***

Good combustion practice has been selected as BACT for CO emissions from the proposed combustion turbines. The use of good combustion practices is expected to achieve CO emissions of 25 ppmvd (at 15% O_2). The following BACT emission limit associated with a CO concentration of 25 ppmvd is proposed for each combustion turbine. The proposed averaging period is the minimum averaging period associated with the carbon monoxide ambient air quality standards.

- Proposed CO BACT Limit: 93.3 lb/hr (1-hour average)

The CO BACT limits expressed for each combustion turbine are for normal operations. During startup and shutdown operations, CO emissions may be greater for certain periods due to unstable combustion associated with lower combustion turbine efficiencies and transitional periods between natural gas and syngas use. Potential emissions for startup and shutdown operations are evaluated as part the modeling analysis presented in Section 7.

5.4.4 Volatile Organic Compound BACT Analysis for the Combustion Turbines

Volatile Organic Compound (VOC) emissions are a product of incomplete combustion. VOC emissions can be reduced by providing adequate fuel residence times and higher temperatures in the combustion zone to ensure complete combustion. The design strategy is to optimize the flame temperature to lower potential NO_x emissions, while minimizing the impact to potential VOC emissions. The combustion turbines for the proposed project will be a GE 7FB model, which is a new design to optimally consume syngas and natural gas. Post-combustion control technologies are have also been used to reduce VOC emissions in some processes.

➢ ***Identify Control Technologies***

The following VOC technologies were evaluated the proposed combustion turbines:

Combustion Process Controls

- Good Combustion Practices

Post Combustion Controls

- SCONOx
- Oxidation Catalysts

➢ ***Evaluate Technical Feasibility***

Good Combustion Practices

Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. This technology has been determined to be BACT for VOC emissions from combustion turbines in other IGCC permits.

SCONOx

The $SCONO_x$ system was evaluated in the NO_x BACT analysis, and determined to be not technically feasible.

Oxidation Catalyst

Catalytic oxidation was evaluated in the CO BACT analysis, and determined to be not technically feasible.

➢ ***Rank Control Technologies***

Good combustion practice is the only technically feasible VOC control technology identified.

➢ ***Evaluate Control Options***

Good combustion practice is the only feasible control technology identified, and has been selected as BACT for other IGCC projects.

➢ ***Select VOC Control Technology***

Good combustion practice has been selected as BACT for VOC emissions from the proposed combustion turbines. The following BACT emission limit is proposed below. The proposed VOC averaging period represents the minimum averaging period associated with the ozone ambient air quality standards.

Proposed VOC BACT Limit: 3.2 lb/hr (8-hour average)

The VOC BACT limits expressed for each combustion turbine are for normal operations. During startup and shutdown operations, VOC emissions may be greater for certain periods due to unstable combustion associated with lower combustion turbine efficiencies and transitional periods between natural gas and syngas use. Potential emissions for startup and shutdown operations are evaluated as part the modeling analysis presented in Section 7.

5.4.5 Particulate Emissions BACT Analysis for the Combustion Turbines

Fuel quality and combustion efficiency are key drivers impacting the quantity and disposition of potential particulate emissions. In some processes, post-combustion control technologies can also be used to reduce particulates.

➢ ***Identify Particulate Emission Control Technologies***

The following particulate emission control technologies were evaluated for the proposed combustion turbines:

Combustion Process Controls

- Clean Fuels with Low Potential Particulate Emissions
- Good Combustion Practices

Post-Combustion Controls:

- Electrostatic Precipitation
- Baghouse

➢ ***Evaluate Technical Feasibility***

Clean Fuels with Low Potential Particulate Emissions

Higher ash content fuels have the potential to produce greater particulate emissions. In addition, fuels containing sulfur have the potential to produce sulfur compounds that may form condensible particulate emissions. Combustion turbine operations require fuels that contain negligible amounts of fuel bound particulate in order to minimize performance impacts. The IGCC process inherently produces a syngas containing minimal amounts of particulate. Any natural gas consumed in the proposed combustion turbines will have a negligible particulate content. The control of syngas sulfur compounds as discussed in the SO_2 BACT will reduce potential condensible particulates. Therefore, the use of clean fuels is a technically feasible control technology.

Good Combustion Practices

The use of good combustion practices is a technically feasible control technology that minimizes particulate emissions resulting from incomplete combustion, and was selected as BACT for CO and VOC emissions.

Electrostatic Precipitation

Electrostatic precipitation (ESP) is a post-combustion particulate control technology most commonly applied to large volume gas streams containing high particulate concentrations, such as with direct combustion coal units. An ESP has not been applied to natural gas combustion turbine operations or IGCC processes due to the low particulate concentrations of the associated exhaust gas streams. Therefore, ESP is not considered technically feasible for the proposed combustion turbines.

Baghouse

A baghouse is a post-combustion control technology that utilizes a fine mesh filter to remove particulate emissions from gas streams, and is most commonly applied to industries producing large volume gas streams with high particulate concentrations. A baghouse has not been applied to natural gas combustion turbine operations or IGCC processes due to the reduced volume and minimal particulate concentration of the associated exhaust gas streams. Thus, a baghouse is not considered technically feasible for the proposed combustion turbines.

➢ ***Rank Control Technologies***

The use of clean fuels with low potential particulate emissions and good combustion practices were identified as the only technically feasible particulate emissions control technologies applicable to the proposed combustion turbines.

➢ ***Evaluate Control Technologies***

The use of clean fuels with low potential particulate emissions and good combustion practices were identified as the only technically feasible particulate emissions control technologies applicable to the proposed combustion turbines. These technologies have been determined to be BACT for other IGCC projects and will result in particulate emission rates that are lower than the revised NSPS rate and recent BACT determinations for pulverized coal units.

➢ ***Select Particulate Emissions Control Technology***
The use of clean fuels with low potential particulate emissions and good combustion practices were selected as BACT for particulate emissions from the proposed combustion turbines. The following BACT emission limit resulting from the implementation of these technologies is proposed for each combustion turbine. The proposed averaging period is the minimum averaging period associated with the particulate matter air quality standards.

- Proposed Particulate Emissions (PM_{10} - filterable) BACT Limit: 18 lb/hr (24-hour average)

The particulate emission BACT limit for each combustion turbine are for normal operations. The potential particulate emission rates during startup and shutdown operations are less than or equal to those for normal operations. Potential emissions for startup and shutdown operations are provided in Section 4 and are evaluated as part of the air dispersion modeling analysis presented in Section 7.

5.5 Sulfur Recovery System Control Technology Review

The sulfur recovery system is designed to process acid gas streams from the acid gas removal (AGR) system and IGCC process into an elemental sulfur by-product. The resulting tail gas exiting the sulfur recovery system is recycled back to the IGCC process during normal operations. Associated with the operation of the sulfur recovery process is the integral use of a flare and thermal oxidizer as control devices to provide for the safe and efficient destruction of combustible gas streams. These control devices are primarily utilized intermittently during short-term periods of startup, shutdown, and malfunction operations. The thermal oxidizer also controls emissions from various systems during normal operations, including the sulfur pit vent. A continuous natural gas pilot will be in service on both controls. The flare and thermal oxidizer are the only control technologies identified that are capable of controlling the variable potential gas streams associated with the sulfur recovery process and the startup, shutdown, and malfunction of the integrated IGCC systems.

➢ ***Identify SO_2, NO_x, CO, VOC, H_2SO_4 and Particulate Emission Control Technologies***

The flare and thermal oxidizer are technologies designed to control potential SO_2, NO_x, CO, VOC, H_2SO_4 and particulate emissions associated with the sulfur recovery process and integrated systems. The following considerations were identified for determining the best available flare and thermal oxidizer control technology design:

Control Technology Considerations

- Flare
- Thermal Oxidizer
- Optimized IGCC Process Design

➢ ***Evaluate Control Technologies***

Flare:

Emissions from the integrated IGCC process cannot be directed to certain control systems and/or the combustion turbines during startup and shutdown operations, or during operational malfunctions. The nature of these emissions will vary widely depending on the operational phase of the IGCC processes and controls. Directly venting these emissions to the atmosphere could result in very high concentrations of SO2, CO, VOC, NOx, and/or H2SO4 being released. A flare reduces emissions and is able to accommodate the variability inherent in these operations. A flare is considered a technically feasible control technology for the sulfur recovery system and startup, shutdown, and malfunction conditions for the integrated IGCC process.

Good design of the flare provides for the safe, reliable, and efficient control of combustible gas streams associated with operation of the sulfur recovery system and IGCC process. Proper design includes the selection of appropriate flare and thermal oxidizer control technologies, along with the incorporation of design specifications that maintain availability and efficiency. Three flare control technologies were evaluated for the proposed facility: an elevated flare, enclosed elevated flare, and an enclosed ground flare. Elevated flare technology utilizes a stack to vent combustible process gases to a burner located at the top resulting in an open flame at the stack discharge. Elevated flares provide for greater dispersion of heat and combustion products than ground flares. Elevated flares are the most common technology used by refinery, steel, and chemical industries, and are used by both IGCC facilities operating in the United States.

The concept of enclosed elevated flares has the potential to minimize flame appearance and provide a setting for monitoring post-combustion gas streams. Through discussions with flare vendors, it was determined that an enclosed elevated flare is not technically feasible for the proposed facility because of safety and reliability concerns. Additionally, the potential quantity of gas handled by the flare would require a structure that would not be cost-effective to construct. Use of an enclosed ground level flare poses similar feasibility and cost issues, with greater safety concerns. Flare vendors indicate that an enclosed ground level flare would not be technically feasible for the proposed facility. Thus, the enclosed elevated and ground flare designs are not technically feasible.

Proper flare design also includes specifications to maintain availability and efficiency. Maintaining the flame integrity is key for optimal and safe flare operation, which may include velocity and heating value requirements of the process gas streams to the flare. A knockout drum to remove moisture from process gas streams is also used to maintain flame integrity. Flame detection monitors and auto ignition systems have also been used to assist in assuring flare availability. Flare efficiency is influenced by temperature, residence time, and the mixing of air and processes gases in the combustion zone. Implementation of these considerations into the design and operations, in combination with the use of a natural gas pilot flame, will support a smokeless flare design that maximizes efficiency and minimizes incomplete combustion, which can impact the control of all emissions. Based on a review of flare designs, an elevated smokeless flare with a knockout drum, flame detectors, auto ignition system, and a natural gas pilot is BACT for the sulfur recovery system and integrate IGCC process.

Thermal Oxidizer

In addition to the flare, process emissions from the sulfur recovery system and sulfur pit vent will be directed to a thermal oxidizer during normal operations and some startup, shutdown, and malfunction conditions. While the thermal oxidizer can control a wide range of emissions, use of the thermal oxidizer in combination of the flare provides the highest degree of emission reduction over the broadest range of operating conditions. The thermal oxidizer is considered technically feasible for the sulfur recovery system.

Proper thermal oxidizer design includes those elements that maintain efficiency, such as temperature, residence time, and the mixing of gas streams in the combustion zone. Minimum design temperature and residence time requirements provide for optimal efficiency and availability. Additionally, natural gas is typically used for preheating and to facilitate the combustion of process gases in the thermal oxidizer. Implementation of these elements into the design and operation of the thermal oxidizer, in combination with the use of a natural gas pilot flame, will support a thermal oxidizer control technology that minimizes incomplete combustion, which can impact the control of all emissions. In summary operation of a well designed thermal oxidizer in combination with a well designed flare is a technically feasible strategy for controlling emissions from the sulfur recovery system and IGCC process.

Optimized IGCC Process Design

Safe, reliable, and cost-effective optimization of the sulfur recovery system and IGCC process design can minimize the frequency and duration of process gas streams to be controlled by the flare and thermal oxidizer. Elements have been incorporated in the design and operating procedures to safely minimize the frequency and duration of gas streams to both controls. One is that the facility is being designed so that the flare does not support load transitions during normal operations. Additionally, a low pressure absorber system has been incorporated in the design of the sulfur recovery system to reduce sulfur concentrations in the gas streams being controlled by the flare and thermal oxidizer. Another factor is the inherent purpose of the proposed facility, which is to provide reliable, affordable electricity. As a result, design elements that maximize the availability of the IGCC unit and minimize startup, shutdown, and malfunction periods will reduce the frequency and duration of flaring events. The development and implementation of process optimizations throughout the engineering and design phase of the project have significantly reduced potential emissions being controlled by the flare and thermal oxidizer. Further optimization is ongoing. Thus, an optimized IGCC process design is considered a technically feasible strategy for using the flare and thermal oxidizer to control emissions from the sulfur recovery process and integrated systems.

- ***Rank Control Technologies***

The flare, thermal oxidizer, and an optimized IGCC process design are each technically feasible strategies for controlling emissions from the sulfur recovery system and integrated IGCC process. These strategies complement one another and be implemented in combination with one another.

➢ ***Select Sulfur Recovery System Control Technologies***

Good control equipment design, good combustion practices, and an optimized IGCC process design have been selected as BACT for the sulfur recovery system. The following BACT conditions are proposed for the sulfur recovery system. In absence of an applicable NSPS, the proposed averaging periods represent the minimum averaging period associated with the national ambient air quality standards or historic averaging periods represented in previous determinations.

Table 5.11: IGCC Sulfur Recovery System BACT Analysis Summary

<table>
<tr><th>Proposed BACT</th><th colspan="3">Proposed BACT Emission Limits</th></tr>
<tr><td rowspan="6"><u>Flare:</u>
Natural Gas Pilot
Smokeless Flare Design
Flame Detection System
Auto-Ignition System
Maximum Gas Velocity

<u>Thermal Oxidizer</u>
Natural Gas Pilot
Minimum Operating Temperature
Low NO_x Burners

<u>Optimized IGCC Process Design</u>
Low Pressure Absorber System
Minimize frequency & duration of control by flare & thermal oxidizer.</td><td>PSD Pollutant</td><td>Flare</td><td>Thermal Oxidizer</td></tr>
<tr><td>SO_2</td><td>684.9 lb/hr
(3-hour average)</td><td>150.9 lb/hr
(3-hour average)</td></tr>
<tr><td>NO_x</td><td>59.4 lb/hr
(24-hour average)</td><td>8.7 lb/hr
(24-hour average)</td></tr>
<tr><td>CO</td><td>312.9 lb/hr
(1-hour average)</td><td>7.4 lb/hr
(1-hour average)</td></tr>
<tr><td>VOC</td><td>0.2 lb/hr
(8-hour average)</td><td>0.5 lb/hr
(8-hour average)</td></tr>
<tr><td>Particulate Emissions</td><td>0.2 lb/hr
(PM_{10} - filterable)
(24-hour average)</td><td>0.7 lb/hr
(PM_{10} - filterable)
(24-hour average)</td></tr>
</table>

5.6 Auxiliary Boiler Control Technology Review

The following is the BACT analysis for the proposed auxiliary boiler, which is designed to provide heat and process steam primarily during startup and shutdown operations, and as necessary to support outage activities. Natural gas will be the only fuel utilized by the auxiliary boiler. Post-combustion control technologies are generally not utilized on auxiliary boilers because of the limited and intermittent use.

5.6.1 NO_x BACT Analysis for the Auxiliary Boiler

NO_x is formed during combustion primarily by the reaction of combustion air nitrogen and oxygen in the high temperature combustion zone (thermal NO_x), or by the oxidation of nitrogen in the fuel (fuel NO_x). The rate of NO_x formation is a function of fuel residence time, oxygen availability, and temperature in the combustion zone. Primary auxiliary boiler NO_x control technologies focus on combustion process controls.

➢ ***Identify All Control Technologies***
The following potential NO_x control technologies were evaluated for the proposed auxiliary boiler.

Combustion Process NOx Controls:
- Low NO_x Burners
- Low NO_x Burners with Flue Gas Recirculation

Post Combustion NOx Controls:
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Non-Selective Catalytic Reduction (NSCR)
- $SCONO_x$

➢ ***Evaluate Technical Feasibility***
Low NOx Burners
Low NO_x burners reduce the formation of thermal NO_x by incorporating a burner design that controls the stoichiometry and temperature of combustion by regulating the distribution and mixing of fuel and air. As a result, fuel-rich pockets in the combustion zone that produce elevated temperatures and higher potential NO_x emissions are minimized. Historically, low NO_x burners have been selected as BACT for natural gas-fired auxiliary boilers. Therefore, low NO_x burner technology is technically feasible for the proposed auxiliary boiler.

Low NOx Burners with Flue Gas Recirculation
Flue gas recirculation (FGR) is used to reduce NO_x emissions in some processes by recirculating a portion of the flue gas into the main combustion chamber. This process reduces the peak combustion temperature and oxygen in the combustion air/flue gas mixture, which reduces the formation of thermal NO_x. FGR has the potential to reduce combustion efficiency resulting in greater carbon monoxide emissions. Application of FGR is typically in combination with low NO_x burner technology and has been selected as BACT for some auxiliary boiler processes. FGR is considered technically feasible for the proposed auxiliary boiler.

Selective Catalytic Reduction (SCR)
SCR is a post-combustion technology that reduces NO_x emissions by reacting NO_x with ammonia in the presence of a catalyst. SCR technology has been most commonly applied pulverized coal generating units and to natural gas fired combustions turbines. No examples have been identified where an SCR has been applied to an auxiliary boiler. The proposed auxiliary boiler will be used during startup and shutdown operations, resulting in varying flue gas characteristics that may not provide for continuous SCR operation. Therefore, SCR is not technically feasible for the intended operation of the auxiliary boiler.

Selective Non-Catalytic Reduction (SNCR)
SNCR is a post-combustion NO_x control technology where ammonia or urea is injected into the exhaust to react with NO_x to form nitrogen and water without the use of a catalyst. Use of this technology is requires uniform mixing of the reagent and exhaust gas within a narrow temperature range. Operations outside of this temperature range will significantly reduce removal efficiencies and may result in ammonia emissions or increased NO_x emissions. No examples were found where SNCR has been applied to an auxiliary boiler. Auxiliary boiler applications are limited by the availability of sufficient residence times and temperature zones. Additionally, the limited use of the proposed auxiliary boilers with varying rates of natural gas combustion further narrow the scope of operating conditions that would support the application of an SNCR. Thus, SNCR is not technically feasible for the proposed auxiliary boiler.

Non-Selective Catalytic Reduction (NSCR)
NSCR is a post combustion control technology that utilizes a catalyst to reduce NO_x emissions under fuel-rich conditions. The technology has been utilized in the automobile industry and for reciprocating engines. No examples have been found NSCR applications to natural gas auxiliary boilers. NSCR technology requires a fuel-rich environment for NO_x reduction, which will not be available in the proposed auxiliary boiler. Therefore, NSCR is not a technically feasible for the proposed auxiliary boiler.

$SCONO_x$
$SCONO_x$ is a post-combustion control technology that utilizes a single catalyst to reduce CO, VOC, and NO_x emissions. Installations on the technology have been limited to small natural gas combustion turbine applications. Recent analyses by state agencies have determined that the technology is currently not feasible for auxiliary boiler applications. For example, the Oregon Department of Environmental Quality (ODEQ) concurred that $SCONO_x$ was not technically feasible for proposed 140 mmBTU/hr auxiliary boiler project. ODEQ also noted a small boiler (4.2 mmBTU/hr) project in California installed a $SCONO_x$ system, but the South Coast Air Quality Management District determined application of the technology could not demonstrate the necessary emission reductions. Based on these determinations and the limited scope of commercial installations, $SCONO_x$ it is not technically feasible for the proposed auxiliary boiler.

➢ ***Rank Control Technologies***
The use of low NO_x burner technology and flue gas recirculation are the only technically feasible control options identified for reducing NO_x emissions. These technologies are commonly used in combination.

➢ ***Evaluate Control Options***
Low NO_x burner technology and flue gas recirculation have historically been selected as BACT for natural gas fired auxiliary boilers. These technologies are commonly used in combination to reduce NO_x emissions.

➢ ***Select NO_x Control Technology***
The use of low NOx burner technology and flue gas recirculation were selected as BACT for NO_x emissions from the proposed auxiliary boiler. The proposed BACT emission limit is presented below. The averaging period is equivalent to that set by NSPS Subpart Db.

- Proposed NO_x BACT Limit: 0.05 lb/mmBTU (30-day average)

5.6.2 CO & VOC BACT Analysis for the Auxiliary Boiler

Potential CO and VOC emissions are due to incomplete combustion that is typically a result of inadequate air and fuel mixing, a lack of available oxygen, or low temperatures in the combustion zone. Fuel quality and good combustion practices can limit CO and VOC emissions. Good combustion practice has commonly been determined as BACT for natural gas fired auxiliary boilers. Post-combustion control technologies utilizing catalytic reduction have also been utilized in some processes to reduce CO and VOC emissions.

➢ ***Identify Control Technologies***
The following CO and VOC control technologies were evaluated for the proposed auxiliary boiler.

<u>Combustion Process Controls</u>

- Good Combustion Practices

<u>Post Combustion Controls</u>

- Oxidation Catalyst
- $SCONO_x$

➢ ***Evaluate Technical Feasibility***
<u>Good Combustion Practices</u>
Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. Good combustion practice has historically been determined as BACT for CO and VOC emissions from auxiliary boilers and is a technically feasible control strategy for the proposed auxiliary boiler.

<u>Oxidation Catalyst</u>
Catalytic oxidation is a post-combustion control technology that utilizes a catalyst to oxidize CO and VOC into CO_2 or H_2O. The technology has most commonly been applied to natural gas fired combustion turbines. No examples were identified where oxidation catalyst technology has been applied to an auxiliary boiler. Because of the low potential CO and VOC emission without an oxidation catalyst and the limited use of the proposed auxiliary boiler, the use of catalytic oxidation technology is determined to be not feasible.

<u>$SCONO_x$</u>
$SCONO_x$ technology was discussed in the NOx BACT analysis and determined to be not technically feasible.

➢ ***Rank Control Technologies***
Good combustion practice is the only feasible control strategy identified, and has historically been selected as BACT for CO and VOC emissions from auxiliary boilers.

➢ ***Evaluate Control Options***
Good combustion practice is the only feasible control strategy identified, and has historically been selected as BACT for CO and VOC emissions from auxiliary boilers.

➢ ***Select CO and VOC Control Technology***
The use of good combustion practices has been selected as BACT for potential CO and VOC emissions from the proposed auxiliary boiler. The BACT limits for CO and VOC emissions are proposed below. In absence of an applicable NSPS, the proposed averaging periods represent the minimum averaging period associated with ambient air quality standards for CO and ozone.

- Proposed CO BACT Limit: 0.08 lb/mmBTU (1-hour)
- Proposed VOC BACT Limit: 0.005 lb/mmBTU (8-hour)

5.6.3 SO_2 and H_2SO_4 BACT Analysis for the Auxiliary Boiler

The auxiliary boiler oxidizes sulfur compounds present in natural gas into SO_2. The control of SO_2 emissions is most directly associated with using a low sulfur fuel such as natural gas. SO_2 emissions may also be controlled using post-combustion control strategies in some processes. The auxiliary boiler has the potential to emit negligible amounts of H_2SO_4 and the BACT analysis will not evaluate potential H_2SO_4 emission controls.

➢ ***Identify SO_2 Control Technologies***

The following SO_2 control technologies were evaluated for the proposed auxiliary boiler.

Pre-Combustion Control

- Low Sulfur Fuels

Post-Combustion Control

- Flue Gas Desulfurization

➢ ***Evaluate Technical Feasibility***

Low Sulfur Fuels

Potential SO_2 emissions are directly related to the sulfur content of fuels. Minimizing fuel sulfur content through the use of low sulfur diesel fuels or natural gas has been determined to be BACT for many combustion processes, including auxiliary boilers. Therefore, utilizing low sulfur fuel is a technically feasible control technology.

Flue Gas Desulfurization

Flue Gas Desulfurization (FGD) is a post-combustion SO_2 control technology that reacts an alkaline solution with SO_2 in the exhaust gas. FGD systems are more readily applied to high SO_2 concentrations gas streams, such as with a pulverized coal unit. FGD has been not applied to an auxiliary boiler due to the low SO_2 concentrations of exhaust streams associated with natural gas combustion. Therefore, FGD technology is not technically feasible for the proposed auxiliary boiler.

➢ ***Rank Control Technologies***

The use of low sulfur fuels is the only technically feasible SO_2 control technology identified for the proposed auxiliary boiler.

➢ ***Select SO2 Control Technology***

The use of low sulfur fuels (natural gas) is selected as BACT for SO_2 emissions from the proposed auxiliary boiler. The proposed BACT limit is presented below. The averaging period is equivalent to that set by NSPS Subpart Db.

- Proposed SO_2 BACT Limit: 0.0007 lb/mmBTU (30-day average)

5.6.4 Particulate Emissions BACT Analysis for the Auxiliary Boiler

Fuel quality and combustion efficiency are key drivers impacting the quantity and disposition of potential particulate emissions. In some processes, post-combustion control technologies can also be used to reduce particulates.

➢ ***Identify Control Technologies***

The following particulate emissions control technologies were evaluated for the proposed auxiliary boiler.

Pre-Combustion Control

- Clean Fuels
- Good Combustion Practice

Post-Combustion Control

- Electrostatic Precipitation
- Baghouse

➢ ***Evaluate Technical Feasibility***

Clean Fuels:

Fuels containing ash have the potential to produce particulate emissions. Additionally, fuels containing sulfur have the potential to produce sulfur compounds that may form condensible particulate emissions. Natural gas consumed by the proposed auxiliary boiler will contain negligible amounts of particulate and is considered a low sulfur fuel. Therefore, the use of clean fuels is technically feasible control technology.

Good Combustion Practice:

The use of good combustion practice is a technically feasible technology that can minimize the potential particulate emissions associated with incomplete combustion.

Electrostatic Precipitation:

Electrostatic precipitation (ESP) is a post-combustion particulate emissions control most readily applied to large volume gas streams containing high particulate concentrations. No examples have been found where an ESP has been applied to a natural gas fired auxiliary boiler due to the reduced volume and minimal particulate concentration of the associated exhaust gas stream. Therefore, ESP is not technically feasible for the proposed auxiliary boiler.

Baghouse:

A baghouse is a post-combustion control technology that utilizes a fine mesh filter to remove particulate emissions primarily from large volume gas streams containing high particulate concentrations. No examples have been found where a baghouse has been applied to a natural gas fired auxiliary boiler due to the reduced volume and minimal particulate concentration of the associated exhaust gas stream. Therefore, baghouse technology is not technically feasible for the proposed auxiliary boiler.

➢ ***Rank Control Technologies***

The use of clean fuels and good combustion practices are the only technically feasible control technologies identified. These technologies are commonly used in combination with one another.

➢ ***Select Particulate Emissions Control Technology***

The use of clean fuels (natural gas) and good combustion practices has been selected as BACT for particulate emissions. The proposed BACT limit is presented below. The averaging time is the minimum period of the associated particulate matter ambient air quality standards.

- Proposed Particulate Emissions (PM_{10} - filterable) BACT: 0.0075 lb/mmBTU (24-hr average)

5.7 Cooling Tower Control Technology Review

The proposed IGCC facility will include a wet mechanical draft cooling tower.

➢ ***Identify Control Technologies***
The following particulate emissions control technologies were evaluated for the proposed cooling tower.

Potential Cooling Tower Control Technology
- Drift Elimination System

➢ ***Evaluate Technical Feasibility***
Drift Elimination System
The cooling tower process involves direct contact cooling between air and the cooling water. As the air passes the water some liquid droplet can become entrained in the air, which is referred to a drift. Potential emissions from the cooling tower are limited to particulate emissions associated with dissolved solids in liquid droplets that may become entrained in the air stream exiting the cooling tower. Cooling towers are designed with drift elimination systems to minimize the potential drift.

The only control technology listed in the EPA BACT Clearinghouse database is the use of drift elimination systems varying from 0.0005% to 0.001% allowable drift depending on the size and type of cooling tower. Drift elimination designs are considered technically feasible for the proposed cooling tower.

➢ ***Rank Control Technologies***
A drift elimination system is the only technically feasible control technology identified for the proposed cooling tower, and has been historically been selected as BACT for other projects.

➢ ***Select Particulate Emissions Control Technology***
A drift elimination system is selected as BACT for the proposed cooling tower. The proposed cooling tower will be designed with a high efficiency drift elimination system to minimize potential drift and particulate emissions. The proposed BACT limit is presented below. The averaging time is the minimum period of the associated particulate matter ambient air quality standards.

- Proposed Particulate Emission (PM_{10} - filterable) BACT: 6.38 lb/hr (24-hour average)

5.8 Material Handling Technology Review

The proposed material handling system is designed to transport and store coal and by-products (slag and sulfur). Potential fugitive particulate emissions are associated with the operation of the material handling system. The EPA BACT Clearinghouse database identifies various forced air dust collectors and/or dust suppression systems as the best industry practices for controlling potential particulate emissions from material handling activities, depending on the nature of the activity.

➢ ***Identify Particulate Emission Control Technologies***

The following particulate emission control technologies were identified for the material handling system:

Process Controls

- Forced Air Dust Collection and Control Systems for fully enclosed activities
- Dust Suppression Systems for exposed material handling activities and storage piles

➢ ***Evaluate Control Technologies***

Forced Air Dust Collection and Control Systems

Forced air dust collection involves capturing potential air streams from activities equipped with a hood or enclosure followed by a filter to remove particulates from the air stream prior to ambient discharge. The most common forced air dust collection and control systems utilize a baghouse or fabric filter. Forced air dust collection has been determined as BACT for a variety of enclosed material handling system operations.

Dust Suppression Systems

Dust suppression systems are designed to minimize the potential formation of fugitive particulate emissions. Common dust suppression technologies include the use of water & chemical suppressants, partial enclosures, paving, and stacking tubes or chutes. Each has been determined as BACT for a variety of exposed material handling system operations.

➢ ***Rank Control Technologies***

Forced air dust collection systems and dust suppression systems have been determined to be technically feasible control technologies for different types of material handling activities. The optimal application of these controls will vary for each type of material handling activity associated with the proposed facility. The following generally summarizes the applicable control technology for each process type associated with the proposed system:

- Conveyors: dust suppression system; enclosure designs;
- Transfer/Reclaim Stations: dust suppression system; stacking tubes; chute enclosures;
- Crushing Activities: forced air dust collection system; enclosure designs;
- Storage piles: water/chemical dust suppression system;
- Roadways & Parking Areas: water/chemical dust suppression system; paving high traffic routes; speed limits;
- Barge Unloader: water/chemical dust suppression system;
- Loading/Unloading Operations: water/chemical dust suppression system; vehicle cleaning.

➢ ***Select Particulate Emission Control Technologies***

The combinations of measures indicated above have been selected as BACT for each type of material handling activity associated with the proposed facility. Compliance demonstration will be based on a system of periodic inspections and the implementation of corrective actions, as necessary. Records of inspections not performed or corrective actions not implemented will be maintained, as necessary.

APPENDIX II

BACT/LAER Analysis

19.0 Best Available Control Technology/Lowest Achievable Emission Rate Analysis

The proposed IGCC project is classified as a new major source of regulated emissions under the Prevention of Significant Deterioration (PSD) and Non-Attainment Major New Source Review (NA-NSR) program. An analysis of the Best Available Control Technology (BACT) is required for sources with potential emissions greater than the PSD established significance thresholds. The BACT analysis evaluates the technical feasibility and cost-effectiveness of emission control options to determine the applicable control technology and emission limits.

The proposed Mountaineer IGCC facility will be located in Mason County, West Virginia. Mason County is currently designated attainment or unclassifiable with all national ambient air quality standards, except fine particulates ($PM_{2.5}$). Mason County has been designated as partial nonattainment with the $PM_{2.5}$ standards only for the Graham tax district, which includes the proposed project site. Current USEPA guidance is to use PM_{10} as a surrogate for $PM_{2.5}$ in the permitting of major new sources. West Virginia non-attainment regulation 45 CSR 19 applies if the potential emission of the nonattainment pollutant is greater than 100 tons per year. A Lowest Achievable Emission Rate (LAER) analysis is required for applicable pollutants greater than the 45 CSR 19 significant thresholds. The LAER analysis focuses on technical feasibility in determining the applicable control technology and emission limits. The table below evaluates the applicability of BACT and LAER requirements.

Table 19-1: BACT and LAER Applicability

Pollutant	Significance Threshold (tpy)	Estimated Facility Potential to Emit (tpy)	BACT Applicable	LAER Applicable
Carbon Monoxide (CO)	100	944	Yes	No
Nitrogen Oxides (NO_x)	40	1,562	Yes	No
Sulfur Dioxide (SO_2)	40	586	Yes	No
Particulate Matter $\leq$10 microns (PM_{10})	100 (LAER)	204 (PM_{10} - filterable)	No	Yes
Volatile Organic Compounds (VOC)	40	83	Yes	No
Sulfuric Acid Mist (H_2SO_4)	7	98	Yes	No
Lead (Pb)	0.6	<0.04	No	No

19.1 BACT/LAER Analysis Summary

A BACT analysis was performed for the potential NO_x, SO_2, H_2SO_4, CO, and VOC emissions from the proposed facility. A LAER analysis was performed for potential particulate emissions. A summary of the proposed control technologies and emission limits resulting from these analyses is provided below. The averaging periods are equivalent to the periods established by the applicable NSPS. In absence of an applicable NSPS, the proposed averaging periods represent the minimum averaging period associated with the national ambient air quality standards or historic averaging periods represented in previous determinations.

Table 19.2: IGCC Combustion Turbine BACT/LAER Analysis Summary

Pollutant	Proposed BACT/LAER	Proposed BACT/LAER Emission Limits (emission limits are per combustion turbine)
NO_x	Diluent Injection to: 15 ppm NO_x (100% syngas) 25 ppm NO_x (100% natural gas)	NO_x Limit (100% syngas): 170.3 lb/hr (30-day ave) NO_x Limit (100% natural gas): 188.9 lb/hr (30-day ave)
SO_2 H_2SO_4	AGR designed to reduce syngas sulfur to 40 ppm (as H_2S)	SO_2 Limit: 51.3 lb/hr (30-day ave) H_2SO_4 Limit: 11.3 lb/hr (30-day ave)
CO	Good Combustion Practices	CO Limit: 93.3 lb/hr (1-hr ave)
VOC	Good Combustion Practices Use of Clean Fuels	VOC Limit: 3.2 lb/hr (8-hr ave)
Particulate Emissions (LAER)	Good Combustion Practices Use of Clean Fuels	Particulate Limit (PM_{10} - filterable): 18 lb/hr (24-hr ave)

Table 19.3: IGCC Sulfur Recovery System BACT/LAER Analysis Summary

Proposed BACT/LAER	Proposed BACT/LAER Emission Limits		
	Pollutant	Flare	Thermal Oxidizer
<u>Flare:</u> Natural Gas Pilot Smokeless Flare Design Flame Detection System Auto-Ignition System Maximum Gas Velocity <u>Thermal Oxidizer</u> Natural Gas Pilot Minimum Operating Temperature Low NO_x Burners <u>Optimized IGCC Process Design</u> Low Pressure Absorber System Minimize frequency & duration of control by flare & thermal oxidizer.	SO_2	684.9 lb/hr (3-hour average)	150.9 lb/hr (3-hour average)
	NO_x	59.4 lb/hr (24-hour average)	8.7 lb/hr (24-hour average)
	CO	312.9 lb/hr (1-hour average)	7.4 lb/hr (1-hour average)
	VOC	0.2 lb/hr (8-hour average)	0.5 lb/hr (8-hour average)
	Particulate Emissions (LAER)	0.2 lb/hr (PM_{10} - filterable) (24-hour average)	0.7 lb/hr (PM_{10} - filterable) (24-hour average)

Table 19.4: Auxiliary Boiler BACT/LAER Analysis Summary

Pollutant	Proposed BACT/LAER	Proposed BACT/LAER Emission Limits	
NO_x	Low NOx Burners Flue Gas Recirculation	NO_x Limit:	0.05 lb/mmBTU (30-day ave)
SO_2	Low Sulfur Fuel (natural gas)	SO_2 Limit:	0.0007 lb/mmBTU (30-day ave)
CO, VOC,	Good Combustion Practices Use of Clean Fuels (natural gas)	CO Limit: VOC Limit	0.08 lb/mmBTU (1-hr ave) 0.005 lb/mmBTU (8-hr ave)
Particulate Emissions (LAER)	Good Combustion Practices Use of Clean Fuels (natural gas)	PM_{10} - filterable:	0.0075 lb/mmBTU (24-hr ave)

Table 19.5: Cooling Tower LAER Analysis Summary

Pollutant	Proposed LAER Technology	Proposed LAER Limits
Particulate Emissions (LAER)	Drift Elimination System	Particulate (PM_{10} - filterable): 6.38 lb/hr (24-hr ave)

Table 19.6: Material Handling LAER Analysis Summary

PSD Pollutant	Proposed LAER Technology	Proposed LAER Limits
Particulate Emissions (LAER)	Forced Air Dust Control Systems Dust Suppression Systems	Periodic observations of fugitive dust sources and implementation of corrective actions (as necessary). Maintain records of inspections not performed or corrective actions not implemented (as necessary).

Table 19.7: Gasifier Preheater BACT/LAER Analysis Summary

Pollutant	Proposed BACT/LAER	Proposed BACT/LAER Emission Limits (emission limits are per gasifier preheater)	
NO_x	Natural Gas Fuel Restricted Operation (startup only) Good Combustion Practices	NO_x Limit:	1.87 lb/hr (30-day ave)
SO_2		SO_2 Limit:	0.22 lb/hr (30-day ave)
CO		CO Limit:	24.7 lb/hr (1-hr ave)
VOC		VOC Limit:	1.6 lb/hr (8-hr ave)
Particulate Emissions (LAER)		Particulate Limit: (PM_{10} - filterable)	2.2 lb/hr (24-hr ave)

Table 19.8: Emergency Generator BACT/LAER Analysis Summary

Pollutant	Proposed BACT/LAER	Proposed BACT/LAER Emission Limits	
NO_x	Restricted Operation (≤500 hrs/yr) Low Sulfur Fuel (≤0.05% Sulfur) Good Combustion Practices	NO_x Limit:	28.6 lb/hr (30-day ave)
SO_2		SO_2 Limit:	0.9 lb/hr (30-day ave)
CO		CO Limit:	12.1 lb/hr (1-hr ave)
VOC		VOC Limit:	1.5 lb/hr (8-hr ave)
Particulate Emissions (LAER)		Particulate Limit: (PM_{10} - filterable)	1.5 lb/hr (24-hr ave)

Table 19.9: Emergency Fire Pump BACT/LAER Analysis Summary

Pollutant	Proposed BACT/LAER	Proposed BACT/LAER Emission Limits	
NO_x	Restricted Operation (≤500 hrs/yr) Low Sulfur Fuel (≤0.05% Sulfur) Good Combustion Practices	NO_x Limit:	13 lb/hr (30-day ave)
SO_2		SO_2 Limit:	0.9 lb/hr (30-day ave)
CO		CO Limit:	2.8 lb/hr (1-hr ave)
VOC		VOC Limit:	1.1 lb/hr (8-hr ave)
Particulate Emissions (LAER)		Particulate Limit: (PM_{10} - filterable)	0.9 lb/hr (24-hr ave)

19.2 BACT/LAER Review Process

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all potentially applicable emission control technologies according to control effectiveness. Evaluation begins with the top or most stringent emission control alternative. If the most stringent control technology is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and the next most stringent control technology is similarly evaluated. This process continues until the BACT option under consideration cannot be eliminated. The top control alternative not eliminated is determined to be BACT. This process involves the following five steps[1]:

- Step 1: Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
- Step 2: Eliminate all technically infeasible control technologies;
- Step 3: Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;
- Step 4: Evaluate most effective controls and document results; and
- Step 5: Select BACT, which will be the most effective practical option not rejected based on economic, environmental, and/or energy impacts.

Formal use of these steps is not always necessary. However, the BACT requirements have consistently been interpreted to contain two core components that must be met in any determination. First, the BACT analysis must consider the most stringent available technologies (those with the potential to provide the maximum reductions). Second, a determination to utilize a technology with a lesser potential control efficiency must be supported by an objective analysis of the associated energy, environmental, and economic impacts. Additionally, the minimum control efficiency evaluated in the BACT analysis must at least achieve emission rates equivalent to applicable New Source Performance Standards.

The process of identifying potential control technologies involves researching many resources, including a review of existing and historical technologies that have been proposed or implemented for other projects and a survey of available literature. Evaluating the applicability of each control option entails an assessment of feasibility and cost-effectiveness. This process determines the potential applicability of a control technology by considering its commercial availability (as evidenced by past or expected near-term deployment on the same or similar types of emission units). An available technology is one that is deemed commercially available because it has progressed through the following development steps: concept stage; research & patenting; bench scale/laboratory testing; pilot scale testing; licensing & commercial demonstration; and commercial sales.

The evaluation process also considers the project specific physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit because of differences in the physical and chemical characteristics of gas streams to be controlled.

The following BACT analysis for the proposed IGCC facility was conducted in a manner consistent with the top-down approach. As part of this analysis, control options for potential reductions were identified by researching the EPA RACT/BACT/LAER Clearinghouse database, by drawing upon engineering and IGCC permitting experience, and by surveying available literature. Potential controls identified were then evaluated as necessary on a technical, economic, environmental, and energy basis.

The LAER analysis required to address PM2.5 nonattainment issues is similar to the BACT analysis, but only considers the technical feasibility of control technology and does not consider economic, energy, or other environmental factors. The NSR Workshop Manual does note however that an emissions limit should not be considered for LAER if the cost of maintaining the associated level of control is so great that a major new source could not be built or operated.

[1] "New Source Review Workshop Manual", DRAFT October 1990, EPA Office of Air Quality Planning and Standards

19.3 Existing and Permitted IGCC Facilities

Air permitting information for the following IGCC projects, which have been issued a final air permit, was reviewed and used in performing the BACT analysis for the proposed AEP IGCC project:

- SG Solutions - Wabash River Generating Station; Indiana (operating);
- Tampa Electric Company - Polk Power Station; Florida (operating);
- WE Energies - Elm Road Generating Station; Wisconsin (permitted/not constructed);
- Global Energy, Inc. - Kentucky Pioneer Energy LLC; Kentucky (permitted/not constructed);
- Global Energy, Inc. - Lima Energy Company; Ohio (permitted/not constructed).

These IGCC projects represent a variety of process designs that not only incorporate different technologies for gasification and syngas cleanup, but also utilize different types and qualities of solid fuels. A variety of different combustion turbine models are also represented. In addition, the size and scope of these projects vary. All of this is indicative of the ongoing development of IGCC technologies. The proposed AEP project further develops and optimizes many of the design concepts proposed and utilized by these permitted projects, and represents a significant first-of-a-kind commercially acceptable scale-up of the IGCC process.

Because of the design and operational differences between permitted IGCC projects, any comparison of emission rates or control technologies can only qualitatively be performed. The comparison is further complicated since only two of the permitted IGCC facilities are in operation, while the others have not been constructed and their emission limits have not yet been demonstrated. In addition, the emission limits are often expressed in different units among permits, which impairs direct comparison between projects.

A general qualitative comparison of permitted IGCC projects and the proposed AEP IGCC project is provided below, which summarizes the estimated combustion turbine emission limits for each project. The emission limits have been estimated based on permit limits and an estimated solid-fuel based gasifier heat input. Nominal preliminary estimates were derived for the proposed AEP project combustion turbines when using syngas at full load. In general, the potential emissions for the proposed AEP project are lower than those for other permitted IGCC projects of varying sizes, technologies, and fuel characteristics.

Table 19.10: Estimated Permitted IGCC Combustion Turbine Emission Rates

Location	Estimated Gasifier Heat Input (MMBtu/hr)	Estimated CO Rate (lb/MMBtu)	Estimated NO_x Rate (lb/MMBtu)	Estimated SO_2 Rate (lb/MMBtu)	*Estimated PE Rate (lb/MMBtu)	Estimated VOC Rate (lb/MMBtu)
Wabash River (operating)	2,356	0.036	0.087	0.126	0.005	0.001
Polk Power Station (operating)	2,191	0.045	0.101	0.170	0.008	0.001
Kentucky Pioneer (not constructed)	4,413	0.026	0.059	0.026	0.009	0.004
Lima Energy (not constructed)	4,413	0.035	0.067	0.022	0.008	0.007
We Energies (not constructed)	5,424	0.024	0.059	0.023	0.008	0.003
AEP IGCC Project (nominal projections)	6,000	0.031	0.057	0.017	0.006	0.001

*The particulate emission rates for permitted projects do not specify the type of particulate represented by the limit. PE estimates for AEP project represent PM_{10} - filterable.

19.4 Combustion Turbine Control Technology Review

The following is the BACT analysis for the proposed combustion turbines. Each of the two proposed combustion turbines will be a GE 7FB model turbine with a nominal capacity of 232 MW. The GE 7FB is a new turbine model designed to optimally utilize syngas and natural gas.

19.4.1 Nitrogen Oxides BACT Analysis for the Combustion Turbines

NO_x is formed during combustion primarily by the reaction of combustion air nitrogen and oxygen within the high temperature combustion zone (thermal NO_x), or by the oxidation of nitrogen in the fuel (fuel NO_x). Because syngas contains negligible amounts of fuel-bound nitrogen, essentially all combustion turbine NO_x emissions originate as thermal NO_x.

The rate of thermal NO_x formation in the combustion turbines is primarily a function of the fuel residence time, availability of oxygen, and peak flame temperature. Several NO_x control technologies are available to reduce the impacts of these variables during the combustion process, including diluent injection and dry low NO_x burner technology. Post-combustion control technologies have also been used in some processes to remove NO_x from the exhaust gas stream.

➢➢ ***Identify Control Technologies***

The following NO_x control technologies were evaluated for the proposed IGCC combustion turbines:

<u>Combustion Process Controls</u>

- Diluent Injection
- Dry Low NO_x burners
- Flue Gas Recirculation

<u>Post Combustion Controls</u>

- SCONOx
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

➢➢ ***Evaluate Technical Feasibility***

<u>Diluent Injection</u>

Higher combustion temperatures may increase thermodynamic efficiency, but may also increase the formation of thermal NO_x. A diluent, such as steam or nitrogen, can be added to the syngas to effectively lower the combustion temperature and formation of thermal NO_x. Diluent injection has been determined as BACT for all currently operating IGCC facilities, and has been demonstrated to achieve NO_x emission rates of 15 ppmvd (at 15% O_2) when firing 100% syngas fuel. It is expected that diluent injection will achieve comparable or more efficient NO_x reductions with the proposed combustion turbines. Because the combustion characteristics of natural gas differ from syngas, the best performance achievable is 25 ppmvd NO_x when using natural gas. Diluent injection also increases the mass flow through the combustion turbine for greater power output. In summary, diluent injection is a technically feasible control technology for the proposed combustion turbines.

<u>Dry Low NO_x Burners</u>

Dry Low-NO_x (DLN) burner technology has successfully been demonstrated to reduce thermal NO_x formation from combustion turbines utilizing natural gas. This technology utilizes a burner design that controls the stoichiometry and temperature of combustion by regulating the distribution and mixing of fuel and air, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions.

Available DLN burner technologies for combustion turbines are designed for natural gas (methane-based) fuels, but are not applicable to combustion turbines utilizing syngas (hydrogen/CO-based), which has a different heating value, gas composition, and flammability characteristics. Research is ongoing to develop DLN technologies for syngas-fueled combustion turbines, but no designs are currently available. Therefore, DLN burner technology is not technically feasible for IGCC due to potential explosion hazards in the combustion section associated with the high content of hydrogen in the syngas.

Flue Gas Recirculation

Flue gas recirculation is being researched by combustion turbine manufactures, but is not currently an available control technology. While the technology may be a future option to reduce NO_x emissions, significant development work is required to complete maturation and integration of the concept into a power plant system, including validating all emissions characteristics and overall plant performance and operability. Additionally, current research efforts have focused on pre-mixed natural gas combustion, and results would need to be expanded to assess syngas applications. Thus, flue gas recirculation is not technically feasible for the proposed combustion turbines.

$SCONO_x$

$SCONO_x$ is a control technology that utilizes a single catalyst to reduce CO, VOC, and NO_x emissions. All installations of the technology have been on small natural gas facilities, and have experienced performance issues. $SCONO_x$ has not been applied to large-scale natural gas combustion turbines, which creates concerns regarding the timing, feasibility, and cost-effectiveness of necessary design improvements. $SCONO_x$ has also not been applied to syngas or exhaust streams containing sulfur in concentrations similar to the proposed project, which creates additional concerns regarding potential catalyst fouling. Therefore, $SCONO_x$ is not technically feasible.

Selective Catalytic Reduction (SCR)

SCR technology has never been attempted on an IGCC plant utilizing coal-derived syngas. BACT analyses for previously permitted IGCC plants have determined SCR is not technically feasible due to concerns regarding catalyst performance and potential operational impacts to downstream equipment. Several analyses noted the unavailability of meaningful performance guarantees from SCR suppliers. In other cases, the application of SCR to the IGCC process was not deemed cost effective due to increased operation & maintenance costs and the costs associated with reducing syngas sulfur to levels that are assumed to be adequate to minimize operational impacts.

AEP's initial evaluation of the application of SCR to IGCC indicates that the uncertainty regarding technical feasibility persists. In discussions with one SCR supplier, the vendor stated that commercial guarantees on catalyst performance and lifespan in a coal-derived syngas would be difficult to obtain. The supplier noted that a research and development (R&D) program would first be needed to address the uncertainties associated with the remaining technical feasibility issues. Without results from such a program, the value of any SCR performance guarantee, if available, would be minimal.

On July 7, 2006, USEPA released a technical report, titled *The Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies,* which includes a discussion regarding the application of SCR to IGCC. Of note, the report acknowledges the differences in applying SCR to IGCC by stating:

> "....there are fundamental differences between natural gas and syngas-fired turbines that make the use of SCR with IGCC technologies more uncertain, and there are no installations at present at IGCC facilities firing coal."

The USEPA report identifies concerns regarding the impacts of ammonium sulfur compounds on the performance and maintenance requirements of downstream equipment. The impact to HRSG (heat recovery steam generator) performance is identified as a crucial question for applying an SCR to an IGCC process. Without an extensive R&D project to identify design characteristics required to alleviate feasibility concerns, it is difficult to evaluate the cost-effectiveness of applying an SCR to IGCC. However, the USEPA report used several assumptions to calculate a cost-effectiveness of $7,920 to $13,120 per ton of NO_x removed by applying an SCR to IGCC. Using these estimates, applying an SCR to IGCC would not be cost-effective even if feasibility issues are addressed.

In summary, no examples have been identified where an SCR has been applied or successfully demonstrated on a coal-derived IGCC unit. Performance uncertainties and unknown risks continue to pose significant technical feasibility concerns. Past AEP experience in applying first of a kind control technologies with inherent unknown operational and performance risks indicates that only through intensive R&D efforts and associated design optimizations can the risks be fully explored and addressed. In the absence of this kind of targeted R&D effort and the associated risk minimization that it would afford, AEP does not believe the technical feasibility issues have been sufficiently addressed to allow SCR to be selected as BACT, especially considering the significant operational and financial risks associated with developing the first generation of commercially acceptable IGCC plants. The basis for this position is summarized by the following:

- SCR has never been applied to IGCC plants utilizing coal-derived syngas.
- The SCR feasibility, cost, and risk issues to be evaluated as part of a BACT analysis are different between IGCC, pulverized coal, and natural gas combined cycle technologies.

- The performance of an SCR catalyst in a coal-derived syngas environment is unknown.
- The syngas sulfur concentrations necessary to alleviate SCR related concerns is unknown.
- The ability to obtain a meaningful performance guarantee is very limited, but is a key factor in determining the technical feasibility of SCR to IGCC.
- Only through an intensive R&D program can risks of applying an SCR to IGCC be explored and addressed.

Selective Non-Catalytic Reduction (SNCR)
SNCR is a post-combustion NO_x control technology in which a reagent (ammonia or urea) is injected in the exhaust gas to react with NO_x to form nitrogen and water without the use of a catalyst. The success of this process in reducing NO_x emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas, which must occur in a very narrow high temperature range. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x, resulting in excess ammonia emissions. SNCR technology is occasionally used in conventional coal-fired heaters or boilers, but it has never been applied to natural gas combined cycle or IGCC units because no locations exist in the heat recovery steam generator with the optimal temperature and residence time that are necessary to accommodate the technology. Therefore, SNCR is not technically feasible.

≻≻ *Rank Control Technologies*
Diluent injection is the only NO_x control technology determined to be technically feasible and commercially available for the proposed IGCC combustion turbines. Diluent injection has been selected as BACT for other permitted IGCC projects.

≻≻ *Evaluate Control Options*
The use of diluent injection was identified as the only technically feasible NO_x control technology for the proposed IGCC combustion turbines. Diluent injection has been demonstrated to reduce NO_x emissions to 15 ppmvd (at 15% O_2) when firing syngas and 25 ppmvd (at 15% O_2) when firing natural gas. The associated potential full load NO_x emission rates are 170.3 lb/hr (100% syngas) and 188.9 lb/hr (100% natural gas). Assuming a nominal gross output from each combustion turbine of 232 MWh and 320 MWh from the common steam generator, the equivalent potential NO_x emission rate is approximately 0.21 lb/MWh (100% syngas) and 0.24 lb/MWh (100% natural gas). Both of these emission rates are significantly lower than the applicable NSPS Subpart Da limit of 1.0 lb/MWh.

≻≻ *Select NO_x Control Technology*
Diluent injection using steam saturation and/or nitrogen has been selected as BACT for the proposed combustion turbines to reduce NO_x emissions to 15 ppm when using syngas and to 25 ppm when using natural gas. The proposed BACT NO_x limits are presented below for each combustion turbine. The averaging periods are equivalent to those set by NSPS Subpart Da.

- Proposed NO_x BACT Limit when burning (100% syngas): 170.3 lb/hr (30-day average)
- Proposed NO_x BACT Limit when burning (100% natural gas): 188.9 lb/hr (30-day average)

The NO_x BACT limits expressed for each combustion turbine are for normal operations. During startup and shutdown operations, NO_x emissions may be greater for certain periods due to unstable combustion associated with lower combustion turbine efficiencies and transitional periods between natural gas and syngas use. Potential emissions for startup and shutdown operations are provided in Appendix I (Emissions Inventory) and are evaluated as part of the air dispersion modeling analysis.

19.4.2 Sulfur Dioxide and Sulfuric Acid Mist BACT Analysis for the Combustion Turbines

The combustion turbines oxidize sulfur compounds in fuel primarily into sulfur dioxide (SO_2). A smaller fraction may form sulfur trioxide (SO_3), which can combine with the moisture in the exhaust to form sulfuric acid mist (H_2SO_4). Emissions can be controlled by limiting the fuel sulfur content or by removing SO_2 from the exhaust gas.

➢➢ ***Identify Control Technologies***

The following SO_2 control technologies were evaluated for the proposed IGCC combustion turbines:

Pre-Combustion Process Controls

- Chemical Absorption Acid Gas Removal
- Physical Absorption Acid Gas Removal

Post-Combustion Controls

- Flue Gas Desulfurization

➢➢ ***Evaluate Technical Feasibility***

Chemical and Physical Acid Gas Removal Systems

During the gasification process, sulfur in the feedstock converts primarily into hydrogen sulfide (H_2S), and will also convert into minor quantities of other sulfur species, such as carbonyl sulfide (COS). Commercially available acid gas removal (AGR) systems are capable of removing greater than 99% of the sulfur compounds from syngas. AGR systems are commonly used for gas sweetening processes of refinery fuel gas or tail gas treatment systems, and are typically coupled with processes that produce useful sulfur by-products. Because COS is not readily removed by AGR systems, a COS hydrolysis unit is often used upstream to convert COS to H_2S for greater total sulfur removal.

AGR systems can employ either chemical or physical absorption methods. Chemical absorption methods are amine-based systems that utilize solvents, such as methyldiethanolamine (MDEA), to bond with the H_2S in the syngas. A stripper column is then used to regenerate the solvent and produce an acid gas stream containing H_2S that can be processed into useful sulfur by-products. An MDEA AGR system has been determined as BACT for all operating and permitted IGCC facilities. The two operating IGCC facilities in the United States both use amine (MDEA) systems to reduce the syngas total sulfur concentration to 100 to 400 ppm[2].

Other types of AGR systems utilize physical absorption methods that employ a physical solvent to remove sulfur from gas streams, such as mixtures of dimethyl ethers of polyethylene glycol (Selexol) or methanol (Rectisol). These systems operate by absorbing H_2S under pressure into the solvent. Dissolved acid gases are removed resulting in a regenerated solvent for reuse and the production of an acid gas stream containing H_2S that can be processed into useful sulfur by-products. Physical absorption methods have historically been used to purify gas streams in the chemical processing and natural gas industries.

In summary, both chemical and physical acid gas removal systems are technically feasible control technologies.

Flue Gas Desulfurization

Flue gas desulfurization (FGD) is a post-combustion SO_2 control technology that reacts an alkaline with SO_2 in the exhaust gas. FGD systems are most commonly used by conventional pulverized coal units and can typically achieve a greater than 95% removal efficiency on new facilities. The FGD process results in a solid by-product that requires the installation of a significant number of ancillary support systems to accommodate treatment, handling, and disposal. FGD is more readily applied to high SO_2 concentration gas streams, such as those present with direct combustion coal units. No examples were identified where an FGD system has been applied to an IGCC facility or similar process. Therefore, FGD is not technically feasible for the proposed combustion turbines. Even if feasible to IGCC processes, FGD could not achieve the high removal efficiencies associated with AGR systems.

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[2] Tampa Electric Polk Power Station IGCC Project – Final Technical Report, August 2002; and Wabash River Coal Gasification Repowering Project – Final Technical Report, August 2000;

➢➢ ***Rank Control Technologies***

Both chemical and physical acid gas removal systems are technically feasible for IGCC processes and can achieve greater than 99% SO_2 removal efficiencies. Table 5.8 summarizes the potential control efficiencies associated with various syngas sulfur concentrations exiting the AGR system.

Table 19.11: AGR SO_2 Control Efficiencies

SO_2 Control Option	Syngas Sulfur (ppm)	Control Efficiency	[1]Nominal Estimate of Annual SO_2 Emissions (tons/year)	[1]Nominal Estimate of SO_2 Emissions Reduction (tons/year)
AGR to 20 ppm	20	99.85 %	234	154,891
AGR to 40 ppm	40	99.7 %	468	154,657
AGR to 100 ppm	100	99.25 %	1,170	153,955
NSPS Subpart Da (95% control option)	---	95 %	7,756	147,369
Uncontrolled	>10,000	---	155,125	---

[1] Nominal design values based on a two gasifier & two combustion turbine configuration

➢➢ ***Evaluate Control Options***

Economic Impacts

Physical and chemical absorption AGR systems can be designed for varying levels of control effectiveness resulting in greater capital and operating costs, along with increase operating risks for greater sulfur removal. Design removal efficiencies among the AGR technologies can overlap, but the capital and operating cost are significantly different. Evaluation of the economic impacts of various AGR design options is complicated by the proposed project being a first-of-a-kind scale-up of IGCC technology. Table 5.9 and Table 5.10 evaluate the cost-effectiveness of using different AGR technologies at various design syngas sulfur concentrations. Estimates are based on nominal design values, input from equipment vendors, and engineering experience.

Results of the analysis indicate the use of a physical absorption based AGR technologies will achieve greater sulfur removal rates more economically than chemical based AGR technologies. Based on this analysis, an AGR design to 40 ppm (expressed as H_2S) represents the best available cost-effective control technology. This level of control is significantly more stringent than the recently finalized New Source Performance Standard requirements and the sulfur removal rates being demonstrated by existing IGCC facilities operating in the United States.

Table 19.12: AGR Cost Estimates

Chemical Solvent based AGR - Cost Estimates

AGR Technology	Syngas Sulfur (ppm)	Sulfur Block Capital Cost (million $)	Annual Capital Recovery Cost (million $)	Operating Cost Steam & Electricity ($1,000/year)	Operating Cost AGR Solvent ($1,000/year)	Operating Cost COS Hydrolysis Catalyst ($1,000/year)	Operating Cost Maintenance ($1,000/year)	Total Annual Operating Cost (million $)	Total Annual Costs (million $)
Chemical Solvent AGR	60	111.4	12.2	4306.0	112.1	1020.8	2811.0	8.3	4314.3
Chemical Solvent AGR	80	97.4	10.7	3881.0	112.1	1020.8	2531.0	7.5	3888.5
Chemical Solvent AGR	100	89.2	9.8	3395.1	112.1	1020.8	2367.0	6.9	3402.0

Notes:
1. Total for two gasifiers & two combustion turbines configuration.
2. Nominal cost estimates for use in performing BACT Analysis only.
3. Annual capital recovery assumes a capital recovery factor of 0.1098 based on a 7% interest rate and 15-year equipment life.

Physical Solvent based AGR - Cost Estimates

AGR Technology	Syngas Sulfur (ppm)	Total Capital Investment (million $)	Annual Capital Recovery Cost (million $)	Operating Cost Steam & Electricity ($1,000/year)	Operating Cost AGR Solvent ($1,000/year)	Operating Cost COS Hydrolysis Catalyst ($1,000/year)	Operating Cost Maintenance ($1,000/year)	Total Annual Operating Cost (million $)	Total Annual Costs (million $)
Physical Solvent AGR	20	178.4	19.6	5311.0	328.8	1020.8	4299.0	11.0	5322.0
Physical Solvent AGR	40	161.0	17.7	4583.0	328.8	1020.8	3878.0	9.8	4592.8
Physical Solvent AGR	60	152.3	16.7	4189.0	328.8	1020.8	3683.8	9.2	4198.2
Physical Solvent AGR	80	146.1	16.0	3950.0	328.8	1020.8	3560.8	8.9	3958.9
Physical Solvent AGR	100	142.7	15.7	3780.0	328.8	1020.8	3493.8	8.6	3788.6

Notes:
1. Total for two gasifiers & two combustion turbines configuration.
2. Nominal cost estimates for use in performing BACT Analysis only.
3. Annual capital recovery assumes a capital recovery factor of 0.1098 based on a 7% interest rate and 15-year equipment life.

Table 19.13: AGR Cost Effectiveness Evaluation

Chemical Solvent based AGR - Cost Effectiveness Evaluation

AGR Technology	Syngas Sulfur (ppm)	Total Capital Investment (million $)	Annual Capital Recovery Cost (million $)	Total Annual Operating Cost (million $)	Total Annual Costs (million $)	Average Cost Effectiveness ($/ton)	Incremental SO_2 Reduction (tons/yr)	Incremental Cost Effectiveness ($/ton)
Chemical Solvent AGR	60	111.4	12.2	8.3	20.5	132.9	231	10,124
Chemical Solvent AGR	80	97.4	10.7	7.5	18.2	118.0	231	6,499
Chemical Solvent AGR	100	89.2	9.8	6.9	16.7	108.4	6,602	2,529

Notes:
1. Total for two gasifiers & two combustion turbines configuration.
2. Nominal cost estimates for use in performing BACT Analysis only.
3. Annual capital recovery assumes a capital recovery factor of 0.1098 based on a 7% interest rate and 15-year equipment life.

Physical Solvent based AGR - Cost Effectiveness Evaluation

AGR Technology	Syngas Sulfur (ppm)	Total Capital Investment (million $)	Annual Capital Recovery Cost (million $)	Total Annual Operating Cost (million $)	Total Annual Costs (million $)	Average Cost Effectiveness ($/ton)	Incremental SO_2 Reduction (tons/yr)	Incremental Cost Effectiveness ($/ton)
Physical Solvent AGR	20	178.4	19.6	11.0	30.6	197.5	231	13,474
Physical Solvent AGR	40	161.0	17.7	9.8	27.5	177.7	231	6,737
Physical Solvent AGR	60	152.3	16.7	9.2	25.9	167.9	231	4,249
Physical Solvent AGR	80	146.1	16.0	8.9	24.9	161.7	231	2,917
Physical Solvent AGR	100	142.7	15.7	8.6	24.3	157.6	6,602	3,676

Notes:
1. Total for two gasifiers & two combustion turbines configuration.
2. Nominal cost estimates for use in performing BACT Analysis only.
3. Annual capital recovery assumes a capital recovery factor of 0.1098 based on a 7% interest rate and 15-year equipment life.
4. Average cost effectiveness vs. nominal uncontrolled rate of 155,125 tpy.

<u>Environmental Impacts</u>
Each AGR design presented in Tables 19.12 and 19.13 reduces syngas sulfur concentrations by greater than 99%, and produces a secondary gas stream that can be processed into potentially useful sulfur by-products. The solvent used by each AGR system will be regenerated and reused. Any related water streams will be treated before discharge. Overall, no collateral environmental issues have been identified that would preclude any of the AGR design options from consideration as BACT for the proposed project.

➢➢ *Select SO_2 Control Technology*
A physical absorption AGR system designed to reduce syngas sulfur concentrations to 40 ppm (expressed as H_2S) has been selected as BACT for SO_2 and H_2SO_4 emissions from the proposed combustion turbines. The proposed AGR system will reduce syngas sulfur content by greater than 99%.

The proposed BACT limits associated with a syngas sulfur content of 40 ppmvd (expressed as H_2S) are presented below for each combustion turbine. The averaging period for SO_2 is equivalent to that established by NSPS Subpart Da. The H_2SO_4 averaging period is proposed to parallel that for SO_2.

- Proposed SO_2 BACT Limit: 51.3 lb/hr (30-day average)
- Proposed H_2SO_4 BACT Limit: 11.3 lb/hr (30-day average)

The potential SO_2 and H_2SO_4 combustion turbine emission rates during startup and shutdown operations are less than or equal to the aforementioned BACT limits for normal operations. Potential emissions for startup and shutdown operations are provided in Appendix I (Emissions Inventory) and are evaluated as part of the air dispersion modeling analysis.

19.4.3 Carbon Monoxide BACT Analysis for the Combustion Turbines

Carbon monoxide (CO) emissions are a result of incomplete combustion. CO emissions can be reduced by providing adequate fuel residence time and higher temperatures in the combustion zone to ensure complete combustion. However, these same control factors can increase NO_x emissions. Conversely, lower NO_x emission rates achieved through flame temperature control (by diluent injection) can increase CO emissions. The design strategy is to optimize the flame temperature to lower potential NO_x emissions, while minimizing the impact to potential CO emissions. The combustion turbines for the proposed project will be a GE 7FB model, which is a new design to optimally consume syngas and natural gas. Post-combustion control technologies have also been used to reduce CO emissions in some processes.

➢➢ ***Identify Control Technologies***
The following CO control technologies were evaluated for the proposed combustion turbines:

Combustion Process Controls
- Good Combustion Practices

Post-Combustion Controls
- $SCONO_x$
- Oxidation Catalyst

➢➢ ***Evaluate Technical Feasibility***
Good Combustion Practices
Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. This technology has been determined to be BACT for CO emissions in other IGCC permits.

SCONOx
The $SCONO_x$ system was evaluated in the NO_x BACT analysis, and determined to be not technically feasible.

Oxidation Catalysts
Catalytic oxidation is a post-combustion control technology that utilizes a catalyst to oxidize CO into CO_2. Trace constituents in the combustion exhaust can create significant concerns regarding the fouling and subsequent reduced performance of the catalyst. Because of these concerns, the use of oxidation catalysts has been limited to processes combusting natural gas. Oxidation catalysts have never been applied to coal-based IGCC processes and pose similar operational and financial risks to those associated with SCR as described in the NO_x BACT analysis, including increased formation of SO_3. Thus, an oxidation catalyst system is not technically feasible.

➢➢ ***Rank Control Technologies***
Good combustion practice is the only technically feasible CO control technology identified.

➢➢ ***Evaluate Control Options***
Good combustion practice is the only feasible control technology identified, and has been selected as BACT for other IGCC projects.

➢➢ ***Select CO Control Technology***
Good combustion practice has been selected as BACT for CO emissions from the proposed combustion turbines. The use of good combustion practices is expected to achieve CO emissions of 25 ppmvd (at 15% O_2). The following BACT emission limit associated with a CO concentration of 25 ppmvd is proposed for each combustion turbine. The proposed averaging period is the minimum averaging period associated with the carbon monoxide ambient air quality standards.

- Proposed CO BACT Limit: 93.3 lb/hr (1-hour average)

The CO BACT limits expressed for each combustion turbine are for normal operations. During startup and shutdown operations, CO emissions may be greater for certain periods due to unstable combustion associated with lower combustion turbine efficiencies and transitional periods between natural gas and syngas use. Potential emissions for startup and shutdown operations are provided in Appendix I (Emissions Inventory) and are evaluated as part of the air dispersion modeling analysis.

19.4.4 Volatile Organic Compound BACT Analysis for the Combustion Turbines

Volatile Organic Compound (VOC) emissions are a product of incomplete combustion. VOC emissions can be reduced by providing adequate fuel residence times and higher temperatures in the combustion zone to ensure complete combustion. The design strategy is to optimize the flame temperature to lower potential NO_x emissions, while minimizing the impact to potential VOC emissions. The combustion turbines for the proposed project will be a GE 7FB model, which is a new design to optimally consume syngas and natural gas. Post-combustion control technologies are have also been used to reduce VOC emissions in some processes.

➢➢ ***Identify Control Technologies***

The following VOC technologies were evaluated the proposed combustion turbines:

Combustion Process Controls
- Good Combustion Practices

Post Combustion Controls
- SCONOx
- Oxidation Catalysts

➢➢ ***Evaluate Technical Feasibility***

Good Combustion Practices

Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. This technology has been determined to be BACT for VOC emissions from combustion turbines in other IGCC permits.

SCONOx

The $SCONO_x$ system was evaluated in the NO_x BACT analysis, and determined to be not technically feasible.

Oxidation Catalyst

Catalytic oxidation was evaluated in the CO BACT analysis, and determined to be not technically feasible.

➢➢ ***Rank Control Technologies***

Good combustion practice is the only technically feasible VOC control technology identified.

➢➢ ***Evaluate Control Options***

Good combustion practice is the only feasible control technology identified, and has been selected as BACT for other IGCC projects.

➢➢ ***Select VOC Control Technology***

Good combustion practice has been selected as BACT for VOC emissions from the proposed combustion turbines. The following BACT emission limit is proposed below. The proposed VOC averaging period represents the minimum averaging period associated with the ozone ambient air quality standards.

Proposed VOC BACT Limit: 3.2 lb/hr (8-hour average)

The VOC BACT limits expressed for each combustion turbine are for normal operations. During startup and shutdown operations, VOC emissions may be greater for certain periods due to unstable combustion associated with lower combustion turbine efficiencies and transitional periods between natural gas and syngas use. Potential emissions for startup and shutdown operations are provided in Appendix I (Emissions Inventory) and are evaluated as part of the air dispersion modeling analysis.

19.4.5 Particulate Emissions LAER Analysis for the Combustion Turbines

Fuel quality and combustion efficiency are key drivers impacting the quantity and disposition of potential particulate emissions. In some processes, post-combustion control technologies can also be used to reduce particulates.

➢➢ *Identify Particulate Emission Control Technologies*
The following particulate emission control technologies were evaluated for the proposed combustion turbines:

Combustion Process Controls
- Clean Fuels with Low Potential Particulate Emissions
- Good Combustion Practices

Post-Combustion Controls:
- Electrostatic Precipitation
- Baghouse

➢➢ *Evaluate Technical Feasibility*
Clean Fuels with Low Potential Particulate Emissions
Higher ash content fuels have the potential to produce greater particulate emissions. In addition, fuels containing sulfur have the potential to produce sulfur compounds that may form condensible particulate emissions. Combustion turbine operations require fuels that contain negligible amounts of fuel bound particulate in order to minimize performance impacts. The IGCC process inherently produces a syngas containing minimal amounts of particulate. Any natural gas consumed in the proposed combustion turbines will have a negligible particulate content. The control of syngas sulfur compounds as discussed in the SO_2 BACT will reduce potential condensible particulates. Therefore, the use of clean fuels is a technically feasible control technology.

Good Combustion Practices
The use of good combustion practices is a technically feasible control technology that minimizes particulate emissions resulting from incomplete combustion, and was selected as BACT for CO and VOC emissions.

Electrostatic Precipitation
Electrostatic precipitation (ESP) is a post-combustion particulate control technology most commonly applied to large volume gas streams containing high particulate concentrations, such as with direct combustion coal units. An ESP has not been applied to natural gas combustion turbine operations or IGCC processes due to the low particulate concentrations of the associated exhaust gas streams. Therefore, ESP is not considered technically feasible for the proposed combustion turbines.

Baghouse
A baghouse is a post-combustion control technology that utilizes a fine mesh filter to remove particulate emissions from gas streams, and is most commonly applied to industries producing large volume gas streams with high particulate concentrations. A baghouse has not been applied to natural gas combustion turbine operations or IGCC processes due to the reduced volume and minimal particulate concentration of the associated exhaust gas streams. Thus, a baghouse is not considered technically feasible for the proposed combustion turbines.

➢➢ *Rank Control Technologies*
The use of clean fuels with low potential particulate emissions and good combustion practices were identified as the only technically feasible particulate emissions control technologies applicable to the proposed combustion turbines.

➢➢ *Evaluate Control Technologies*
The use of clean fuels with low potential particulate emissions and good combustion practices were identified as the only technically feasible particulate emissions control technologies applicable to the proposed combustion turbines. These technologies have been determined to be BACT for other IGCC projects and will result in particulate emission rates that are lower than the revised NSPS rate and recent BACT determinations for pulverized coal units. No examples were found regarding the application of LAER for particulate emissions associated with natural gas or syngas combustion in a combustion turbine. Therefore, BACT and LAER are equivalent for the proposed combustion turbines.

➤➤ ***Select Particulate Emissions Control Technology***
The use of clean fuels with low potential particulate emissions and good combustion practices were selected as LAER for particulate emissions from the proposed combustion turbines. The following emission limit resulting from the implementation of these technologies is proposed for each combustion turbine. The proposed averaging period is the minimum averaging period associated with the particulate matter air quality standards.

- Proposed Particulate Emissions (PM_{10} - filterable) BACT Limit: 18 lb/hr (24-hour average)

The particulate emission LAER limit for each combustion turbine are for normal operations. The potential particulate emission rates during startup and shutdown operations are less than or equal to those for normal operations. Potential emissions for startup and shutdown operations are provided in Appendix I (Emissions Inventory) and are evaluated as part of the air dispersion modeling analysis.

19.5 Sulfur Recovery System Control Technology Review

The sulfur recovery system is designed to process acid gas streams from the acid gas removal (AGR) system and IGCC process into an elemental sulfur by-product. The resulting tail gas exiting the sulfur recovery system is recycled back to the IGCC process during normal operations. Associated with the operation of the sulfur recovery process is the integral use of a flare and thermal oxidizer as control devices to provide for the safe and efficient destruction of combustible gas streams. These control devices are primarily utilized intermittently during short-term periods of startup, shutdown, and malfunction operations. The thermal oxidizer also controls emissions from various systems during normal operations, including the sulfur pit vent. A continuous natural gas pilot will be in service on both controls. The flare and thermal oxidizer are the only control technologies identified that are capable of controlling the variable potential gas streams associated with the sulfur recovery process and the startup, shutdown, and malfunction of the integrated IGCC systems.

➢➢ Identify SO_2, NO_x, CO, VOC, H_2SO_4 and Particulate Emission Control Technologies

The flare and thermal oxidizer are technologies designed to control potential SO_2, NO_x, CO, VOC, H_2SO_4 and particulate emissions associated with the sulfur recovery process and integrated systems. The following considerations were identified for determining the best available flare and thermal oxidizer control technology design:

Control Technology Considerations

- Flare
- Thermal Oxidizer
- Optimized IGCC Process Design

➢➢ Evaluate Control Technologies

Flare:

Emissions from the integrated IGCC process cannot be directed to certain control systems and/or the combustion turbines during startup and shutdown operations, or during operational malfunctions. The nature of these emissions will vary widely depending on the operational phase of the IGCC processes and controls. Directly venting these emissions to the atmosphere could result in very high concentrations of SO2, CO, VOC, NOx, and/or H2SO4 being released. A flare reduces emissions and is able to accommodate the variability inherent in these operations. A flare is considered a technically feasible control technology for the sulfur recovery system and startup, shutdown, and malfunction conditions for the integrated IGCC process.

Good design of the flare provides for the safe, reliable, and efficient control of combustible gas streams associated with operation of the sulfur recovery system and IGCC process. Proper design includes the selection of appropriate flare and thermal oxidizer control technologies, along with the incorporation of design specifications that maintain availability and efficiency. Three flare control technologies were evaluated for the proposed facility: an elevated flare, enclosed elevated flare, and an enclosed ground flare. Elevated flare technology utilizes a stack to vent combustible process gases to a burner located at the top resulting in an open flame at the stack discharge. Elevated flares provide for greater dispersion of heat and combustion products than ground flares. Elevated flares are the most common technology used by refinery, steel, and chemical industries, and are used by both IGCC facilities operating in the United States.

The concept of enclosed elevated flares has the potential to minimize flame appearance and provide a setting for monitoring post-combustion gas streams. Through discussions with flare vendors, it was determined that an enclosed elevated flare is not technically feasible for the proposed facility because of safety and reliability concerns. Additionally, the potential quantity of gas handled by the flare would require a structure that would not be cost-effective to construct. Use of an enclosed ground level flare poses similar feasibility and cost issues, with greater safety concerns. Flare vendors indicate that an enclosed ground level flare would not be technically feasible for the proposed facility. Thus, the enclosed elevated and ground flare designs are not technically feasible.

Proper flare design also includes specifications to maintain availability and efficiency. Maintaining the flame integrity is key for optimal and safe flare operation, which may include velocity and heating value requirements of the process gas streams to the flare. A knockout drum to remove moisture from process gas streams is also used to maintain flame integrity. Flame detection monitors and auto ignition systems have also been used to assist in assuring flare availability. Flare efficiency is influenced by temperature, residence time, and the mixing of air and processes gases in the combustion zone. Implementation of these considerations into the design and operations, in combination with the use of a natural gas pilot flame, will support a smokeless flare design that maximizes efficiency and minimizes incomplete combustion, which can impact the control of all emissions. Based on a review of flare designs, an elevated smokeless flare with a knockout drum, flame detectors, auto ignition system, and a natural gas pilot is BACT and LAER for the sulfur recovery system and integrate IGCC process.

Thermal Oxidizer

In addition to the flare, process emissions from the sulfur recovery system and sulfur pit vent will be directed to a thermal oxidizer during normal operations and some startup, shutdown, and malfunction conditions. While the thermal oxidizer can control a wide range of emissions, use of the thermal oxidizer in combination of the flare provides the highest degree of emission reduction over the broadest range of operating conditions. The thermal oxidizer is considered technically feasible for the sulfur recovery system.

Proper thermal oxidizer design includes those elements that maintain efficiency, such as temperature, residence time, and the mixing of gas streams in the combustion zone. Minimum design temperature and residence time requirements provide for optimal efficiency and availability. Additionally, natural gas is typically used for preheating and to facilitate the combustion of process gases in the thermal oxidizer. Implementation of these elements into the design and operation of the thermal oxidizer, in combination with the use of a natural gas pilot flame, will support a thermal oxidizer control technology that minimizes incomplete combustion, which can impact the control of all emissions. In summary operation of a well designed thermal oxidizer in combination with a well designed flare is a technically feasible strategy for controlling emissions from the sulfur recovery system and IGCC process.

Optimized IGCC Process Design

Safe, reliable, and cost-effective optimization of the sulfur recovery system and IGCC process design can minimize the frequency and duration of process gas streams to be controlled by the flare and thermal oxidizer. Elements have been incorporated in the design and operating procedures to safely minimize the frequency and duration of gas streams to both controls. One is that the facility is being designed so that the flare does not support load transitions during normal operations. Additionally, a low pressure absorber system has been incorporated in the design of the sulfur recovery system to reduce sulfur concentrations in the gas streams being controlled by the flare and thermal oxidizer. Another factor is the inherent purpose of the proposed facility, which is to provide reliable, affordable electricity. As a result, design elements that maximize the availability of the IGCC unit and minimize startup, shutdown, and malfunction periods will reduce the frequency and duration of flaring events. The development and implementation of process optimizations throughout the engineering and design phase of the project have significantly reduced potential emissions being controlled by the flare and thermal oxidizer. Further optimization is ongoing. Thus, an optimized IGCC process design is considered a technically feasible strategy for using the flare and thermal oxidizer to control emissions from the sulfur recovery process and integrated systems.

➢➢ ***Rank Control Technologies***

The flare, thermal oxidizer, and an optimized IGCC process design are each technically feasible strategies for controlling emissions from the sulfur recovery system and integrated IGCC process. These strategies complement one another and be implemented in combination with one another. No examples were found regarding the application of LAER for particulate emissions associated with sulfur recovery systems. However, the potential annual particulate emissions from the proposed sulfur recovery system are negligible (<1.1 tpy PM_{10} filterable) Therefore, BACT and LAER are determined to be equivalent for the proposed sulfur recovery system.

➢➢ ***Select Sulfur Recovery System Control Technologies***

Good control equipment design, good combustion practices, and an optimized IGCC process design have been selected as BACT/LAER for the sulfur recovery system. The following BACT/LAER conditions are proposed for the sulfur recovery system. In absence of an applicable NSPS, the proposed averaging periods represent the minimum averaging period associated with the national ambient air quality standards or historic averaging periods represented in previous determinations.

Table 19.14: IGCC Sulfur Recovery System BACT/LAER Analysis Summary

<table>
<tr><th>Proposed BACT/LAER</th><th colspan="3">Proposed BACT/LAER Emission Limits</th></tr>
<tr><td rowspan="6"><u>Flare:</u>
Natural Gas Pilot
Smokeless Flare Design
Flame Detection System
Auto-Ignition System
Maximum Gas Velocity

<u>Thermal Oxidizer</u>
Natural Gas Pilot
Minimum Operating Temperature
Low NO_x Burners

<u>Optimized IGCC Process Design</u>
Low Pressure Absorber System
Minimize frequency & duration of control by flare & thermal oxidizer.</td><th>PSD Pollutant</th><th>Flare</th><th>Thermal Oxidizer</th></tr>
<tr><td>SO_2</td><td>684.9 lb/hr
(3-hour average)</td><td>150.9 lb/hr
(3-hour average)</td></tr>
<tr><td>NO_x</td><td>59.4 lb/hr
(24-hour average)</td><td>8.7 lb/hr
(24-hour average)</td></tr>
<tr><td>CO</td><td>312.9 lb/hr
(1-hour average)</td><td>7.4 lb/hr
(1-hour average)</td></tr>
<tr><td>VOC</td><td>0.2 lb/hr
(8-hour average)</td><td>0.5 lb/hr
(8-hour average)</td></tr>
<tr><td>Particulate Emissions (LAER)</td><td>0.2 lb/hr
(PM_{10} - filterable)
(24-hour average)</td><td>0.7 lb/hr
(PM_{10} - filterable)
(24-hour average)</td></tr>
</table>

19.6 Auxiliary Boiler Control Technology Review

The following is the BACT analysis for the proposed auxiliary boiler, which is designed to provide heat and process steam primarily during startup and shutdown operations, and as necessary to support outage activities. Natural gas will be the only fuel utilized by the auxiliary boiler. Post-combustion control technologies are generally not utilized on auxiliary boilers because of the limited and intermittent use.

19.6.1 NO_x BACT Analysis for the Auxiliary Boiler

NO_x is formed during combustion primarily by the reaction of combustion air nitrogen and oxygen in the high temperature combustion zone (thermal NO_x), or by the oxidation of nitrogen in the fuel (fuel NO_x). The rate of NO_x formation is a function of fuel residence time, oxygen availability, and temperature in the combustion zone. Primary auxiliary boiler NO_x control technologies focus on combustion process controls.

➢➢ ***Identify All Control Technologies***
The following potential NO_x control technologies were evaluated for the proposed auxiliary boiler.

Combustion Process NOx Controls:
- Low NO_x Burners
- Low NO_x Burners with Flue Gas Recirculation

Post Combustion NOx Controls:
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Non-Selective Catalytic Reduction (NSCR)
- $SCONO_x$

➢➢ ***Evaluate Technical Feasibility***
Low NOx Burners
Low NO_x burners reduce the formation of thermal NO_x by incorporating a burner design that controls the stoichiometry and temperature of combustion by regulating the distribution and mixing of fuel and air. As a result, fuel-rich pockets in the combustion zone that produce elevated temperatures and higher potential NO_x emissions are minimized. Historically, low NO_x burners have been selected as BACT for natural gas-fired auxiliary boilers. Therefore, low NO_x burner technology is technically feasible for the proposed auxiliary boiler.

Low NOx Burners with Flue Gas Recirculation
Flue gas recirculation (FGR) is used to reduce NO_x emissions in some processes by recirculating a portion of the flue gas into the main combustion chamber. This process reduces the peak combustion temperature and oxygen in the combustion air/flue gas mixture, which reduces the formation of thermal NO_x. FGR has the potential to reduce combustion efficiency resulting in greater carbon monoxide emissions. Application of FGR is typically in combination with low NO_x burner technology and has been selected as BACT for some auxiliary boiler processes. FGR is considered technically feasible for the proposed auxiliary boiler.

Selective Catalytic Reduction (SCR)
SCR is a post-combustion technology that reduces NO_x emissions by reacting NO_x with ammonia in the presence of a catalyst. SCR technology has been most commonly applied pulverized coal generating units and to natural gas fired combustions turbines. No examples have been identified where an SCR has been applied to an auxiliary boiler. The proposed auxiliary boiler will be used during startup and shutdown operations, resulting in varying flue gas characteristics that may not provide for continuous SCR operation. Therefore, SCR is not technically feasible for the intended operation of the auxiliary boiler.

Selective Non-Catalytic Reduction (SNCR)
SNCR is a post-combustion NO_x control technology where ammonia or urea is injected into the exhaust to react with NO_x to form nitrogen and water without the use of a catalyst. Use of this technology is requires uniform mixing of the reagent and exhaust gas within a narrow temperature range. Operations outside of this temperature range will significantly reduce removal efficiencies and may result in ammonia emissions or increased NO_x emissions. No examples were found where SNCR has been applied to an auxiliary boiler. Auxiliary boiler applications are limited by the availability of sufficient residence times and temperature zones. Additionally, the limited use of the proposed auxiliary boilers with varying rates of natural gas combustion further narrow the scope of operating conditions that would support the application of an SNCR. Thus, SNCR is not technically feasible for the proposed auxiliary boiler..

Non-Selective Catalytic Reduction (NSCR)
NSCR is a post combustion control technology that utilizes a catalyst to reduce NO_x emissions under fuel-rich conditions. The technology has been utilized in the automobile industry and for reciprocating engines. No examples have been found NSCR applications to natural gas auxiliary boilers. NSCR technology requires a fuel-rich environment for NO_x reduction, which will not be available in the proposed auxiliary boiler. Therefore, NSCR is not a technically feasible for the proposed auxiliary boiler.

$SCONO_x$
$SCONO_x$ is a post-combustion control technology that utilizes a single catalyst to reduce CO, VOC, and NO_x emissions. Installations on the technology have been limited to small natural gas combustion turbine applications. Recent analyses by state agencies have determined that the technology is currently not feasible for auxiliary boiler applications. For example, the Oregon Department of Environmental Quality (ODEQ) concurred that $SCONO_x$ was not technically feasible for proposed 140 mmBTU/hr auxiliary boiler project. ODEQ also noted a small boiler (4.2 mmBTU/hr) project in California installed a $SCONO_x$ system, but the South Coast Air Quality Management District determined application of the technology could not demonstrate the necessary emission reductions. Based on these determinations and the limited scope of commercial installations, $SCONO_x$ it is not technically feasible for the proposed auxiliary boiler.

➢➢ ***Rank Control Technologies***
The use of low NO_x burner technology and flue gas recirculation are the only technically feasible control options identified for reducing NO_x emissions. These technologies are commonly used in combination.

➢➢ ***Evaluate Control Options***
Low NO_x burner technology and flue gas recirculation have historically been selected as BACT for natural gas fired auxiliary boilers. These technologies are commonly used in combination to reduce NO_x emissions.

➢➢ ***Select NO_x Control Technology***
The use of low NOx burner technology and flue gas recirculation were selected as BACT for NO_x emissions from the proposed auxiliary boiler. The proposed BACT emission limit is presented below. The averaging period is equivalent to that set by NSPS Subpart Db.

- Proposed NO_x BACT Limit: 0.05 lb/mmBTU (30-day average)

19.6.2 CO & VOC BACT Analysis for the Auxiliary Boiler

Potential CO and VOC emissions are due to incomplete combustion that is typically a result of inadequate air and fuel mixing, a lack of available oxygen, or low temperatures in the combustion zone. Fuel quality and good combustion practices can limit CO and VOC emissions. Good combustion practice has commonly been determined as BACT for natural gas fired auxiliary boilers. Post-combustion control technologies utilizing catalytic reduction have also been utilized in some processes to reduce CO and VOC emissions.

➢➢ ***Identify Control Technologies***
The following CO and VOC control technologies were evaluated for the proposed auxiliary boiler.

<u>Combustion Process Controls</u>

- Good Combustion Practices

<u>Post Combustion Controls</u>

- Oxidation Catalyst
- $SCONO_x$

➢➢ ***Evaluate Technical Feasibility***
<u>Good Combustion Practices</u>
Good combustion practices include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete combustion. Good combustion practice has historically been determined as BACT for CO and VOC emissions from auxiliary boilers and is a technically feasible control strategy for the proposed auxiliary boiler.

<u>Oxidation Catalyst</u>
Catalytic oxidation is a post-combustion control technology that utilizes a catalyst to oxidize CO and VOC into CO_2 or H_2O. The technology has most commonly been applied to natural gas fired combustion turbines. No examples were identified where oxidation catalyst technology has been applied to an auxiliary boiler. Because of the low potential CO and VOC emission without an oxidation catalyst and the limited use of the proposed auxiliary boiler, the use of catalytic oxidation technology is determined to be not feasible.

<u>$SCONO_x$</u>
$SCONO_x$ technology was discussed in the NOx BACT analysis and determined to be not technically feasible.

➢➢ ***Rank Control Technologies***
Good combustion practice is the only feasible control strategy identified, and has historically been selected as BACT for CO and VOC emissions from auxiliary boilers.

➢➢ ***Evaluate Control Options***
Good combustion practice is the only feasible control strategy identified, and has historically been selected as BACT for CO and VOC emissions from auxiliary boilers.

➢➢ ***Select CO and VOC Control Technology***
The use of good combustion practices has been selected as BACT for potential CO and VOC emissions from the proposed auxiliary boiler. The BACT limits for CO and VOC emissions are proposed below. In absence of an applicable NSPS, the proposed averaging periods represent the minimum averaging period associated with ambient air quality standards for CO and ozone.

- Proposed CO BACT Limit: 0.08 lb/mmBTU (1-hour)
- Proposed VOC BACT Limit: 0.005 lb/mmBTU (8-hour)

19.6.3 SO_2 and H_2SO_4 BACT Analysis for the Auxiliary Boiler

The auxiliary boiler oxidizes sulfur compounds present in natural gas into SO_2. The control of SO_2 emissions is most directly associated with using a low sulfur fuel such as natural gas. SO_2 emissions may also be controlled using post-combustion control strategies in some processes. The auxiliary boiler has the potential to emit negligible amounts of H_2SO_4 and the BACT analysis will not evaluate potential H_2SO_4 emission controls.

➢➢ ***Identify SO_2 Control Technologies***
The following SO_2 control technologies were evaluated for the proposed auxiliary boiler.

<u>Pre-Combustion Control</u>

- Low Sulfur Fuels

<u>Post-Combustion Control</u>

- Flue Gas Desulfurization

➢➢ ***Evaluate Technical Feasibility***
<u>Low Sulfur Fuels</u>
Potential SO_2 emissions are directly related to the sulfur content of fuels. Minimizing fuel sulfur content through the use of low sulfur diesel fuels or natural gas has been determined to be BACT for many combustion processes, including auxiliary boilers. Therefore, utilizing low sulfur fuel is a technically feasible control technology.

<u>Flue Gas Desulfurization</u>
Flue Gas Desulfurization (FGD) is a post-combustion SO_2 control technology that reacts an alkaline solution with SO_2 in the exhaust gas. FGD systems are more readily applied to high SO_2 concentrations gas streams, such as with a pulverized coal unit. FGD has been not applied to an auxiliary boiler due to the low SO_2 concentrations of exhaust streams associated with natural gas combustion. Therefore, FGD technology is not technically feasible for the proposed auxiliary boiler.

➢➢ ***Rank Control Technologies***
The use of low sulfur fuels is the only technically feasible SO_2 control technology identified for the proposed auxiliary boiler.

➢➢ ***Select SO2 Control Technology***
The use of low sulfur fuels (natural gas) is selected as BACT for SO_2 emissions from the proposed auxiliary boiler. The proposed BACT limit is presented below. The averaging period is equivalent to that set by NSPS Subpart Db.

- Proposed SO_2 BACT Limit: 0.0007 lb/mmBTU (30-day average)

19.6.4 Particulate Emissions LAER Analysis for the Auxiliary Boiler

Fuel quality and combustion efficiency are key drivers impacting the quantity and disposition of potential particulate emissions. In some processes, post-combustion control technologies can also be used to reduce particulates.

➢➢ ***Identify Control Technologies***
The following particulate emissions control technologies were evaluated for the proposed auxiliary boiler.

Pre-Combustion Control
- Clean Fuels
- Good Combustion Practice
- Restricted Operations

Post-Combustion Control
- Electrostatic Precipitation
- Baghouse

➢➢ ***Evaluate Technical Feasibility***
Clean Fuels:
Fuels containing ash have the potential to produce particulate emissions. Additionally, fuels containing sulfur have the potential to produce sulfur compounds that may form condensible particulate emissions. Natural gas consumed by the proposed auxiliary boiler will contain negligible amounts of particulate and is considered a low sulfur fuel. Therefore, the use of clean fuels is technically feasible control technology.

Good Combustion Practice:
The use of good combustion practice is a technically feasible technology that can minimize the potential particulate emissions associated with incomplete combustion.

Restricted Operations:
Potential particulate emissions are limited by the auxiliary boiler only being used to support startup and shutdown operations .

Electrostatic Precipitation:
Electrostatic precipitation (ESP) is a post-combustion particulate emissions control most readily applied to large volume gas streams containing high particulate concentrations. No examples have been found where an ESP has been applied to a natural gas fired auxiliary boiler due to the reduced volume and minimal particulate concentration of the associated exhaust gas stream. Therefore, ESP is not technically feasible for the proposed auxiliary boiler.

Baghouse:
A baghouse is a post-combustion control technology that utilizes a fine mesh filter to remove particulate emissions primarily from large volume gas streams containing high particulate concentrations. No examples have been found where a baghouse has been applied to a natural gas fired auxiliary boiler due to the reduced volume and minimal particulate concentration of the associated exhaust gas stream. Therefore, baghouse technology is not technically feasible for the proposed auxiliary boiler.

➢➢ ***Rank Control Technologies***
The use of clean fuels and good combustion practices are the only technically feasible control technologies identified. Potential emissions from the auxiliary boiler are also restricted by the auxiliary boiler only being used to support startup and shutdown operations. No examples were found regarding the application of LAER for particulate emissions associated with natural gas combustion. However, the potential particulate emissions from each gasifier are low (<6 tpy PM_{10}-filterable).

➢➢ ***Select Particulate Emissions Control Technology***
The use of clean fuels (natural gas) and good combustion practices has been selected as LAER. The proposed LAER limit is presented below. The averaging time is the minimum period of the associated particulate matter ambient air quality standards.

- Proposed Particulate Emissions (PM_{10} - filterable) LAER: 0.0075 lb/mmBTU (24-hr average)

19.7 Cooling Tower Control Technology Review

The proposed IGCC facility will include a wet mechanical draft cooling tower.

➢➢ *Identify Control Technologies*

The following particulate emissions control technologies were evaluated for the proposed cooling tower.

Potential Cooling Tower Control Technology

- Drift Elimination System

➢➢ *Evaluate Technical Feasibility*

Drift Elimination System

The cooling tower process involves direct contact cooling between air and the cooling water. As the air passes the water some liquid droplet can become entrained in the air, which is referred to a drift. Potential emissions from the cooling tower are limited to particulate emissions associated with dissolved solids in liquid droplets that may become entrained in the air stream exiting the cooling tower. Cooling towers are designed with drift elimination systems to minimize the potential drift.

The only control technology listed in the EPA BACT/LAER Clearinghouse database is the use of drift elimination systems varying from 0.0005% to 0.001% allowable drift depending on the size and type of cooling tower. Drift elimination designs are considered technically feasible for the proposed cooling tower.

➢➢ *Rank Control Technologies*

A drift elimination system is the only technically feasible control technology identified for the proposed cooling tower, and has been historically been selected as BACT for other projects. No examples were found regarding the application of LAER for particulate emissions from cooling towers.

➢➢ *Select Particulate Emissions Control Technology*

A drift elimination system is selected as LAER for the proposed cooling tower. The proposed cooling tower will be designed with a high efficiency drift elimination system to minimize potential drift and particulate emissions. The proposed LAER limit is presented below. The averaging time is the minimum period of the associated particulate matter ambient air quality standards.

- Proposed Particulate Emission (PM_{10} - filterable) LAER: 6.38 lb/hr (24-hour average)

19.8 Material Handling Technology Review

The proposed material handling system is designed to transport and store coal and by-products (slag and sulfur). Potential fugitive particulate emissions are associated with the operation of the material handling system. The EPA BACT Clearinghouse database identifies various forced air dust collectors and/or dust suppression systems as the best industry practices for controlling potential particulate emissions from material handling activities, depending on the nature of the activity.

➢➢ ***Identify Particulate Emission Control Technologies***
The following particulate emission control technologies were identified for the material handling system:

Process Controls
- Forced Air Dust Collection and Control Systems for fully enclosed activities
- Dust Suppression Systems for exposed material handling activities and storage piles

➢➢ ***Evaluate Control Technologies***
Forced Air Dust Collection and Control Systems
Forced air dust collection involves capturing potential air streams from activities equipped with a hood or enclosure followed by a filter to remove particulates from the air stream prior to ambient discharge. The most common forced air dust collection and control systems utilize a baghouse or fabric filter.

Dust Suppression Systems
Dust suppression systems are designed to minimize the potential formation of fugitive particulate emissions. Common dust suppression technologies include the use of water & chemical suppressants, partial enclosures, paving, and stacking tubes or chutes.

➢➢ ***Rank Control Technologies***
Forced air dust collection systems and dust suppression systems have been determined to be technically feasible control technologies for different types of material handling activities. The optimal application of these controls will vary for each type of material handling activity associated with the proposed facility. The following generally summarizes the applicable control technology for each process type associated with the proposed system:
- Conveyors: dust suppression system; enclosure designs;
- Transfer/Reclaim Stations: dust suppression system; stacking tubes; chute enclosures;
- Crushing Activities: forced air dust collection system; enclosure designs;
- Storage piles: water/chemical dust suppression system;
- Roadways & Parking Areas: water/chemical dust suppression system; paving high traffic routes; speed limits;
- Barge Unloader: water/chemical dust suppression system;
- Loading/Unloading Operations: water/chemical dust suppression system; vehicle cleaning.

➢➢ ***Select Particulate Emission Control Technologies***
The combinations of measures indicated above have been selected as LAER for each type of material handling activity associated with the proposed facility. Compliance demonstration will be based on a system of periodic inspections and the implementation of corrective actions, as necessary. Records of inspections not performed or corrective actions not implemented will be maintained, as necessary.

19.9 Gasifier Preheating Control Technology Review

During startup operations, natural gas is utilized in each gasifier to preheat the refractory lining prior to commencing syngas production. Potential emissions from the natural gas combustion in the gasifier are exhausted from a preheat vent located on each gasifier. The primary potential emissions from the gasifier preheat vents are NO_x and CO. Each gasifier preheat vent has a potential to emit less than 5 tons per year of NO_x and CO as discussed in the emission inventory presented in Section 4.0. Good combustion controls that optimize burner efficiency will minimize potential NO_x and CO emissions. Because natural gas is being used for preheating, the potential emissions of SO_2, and VOC will be negligible (<0.1 tpy).

No examples were found regarding the application of LAER for particulate emissions associated with natural gas combustion. The potential particulate emissions from each gasifier are negligible (less than 0.2 tons/year PM_{10}-filterable). Therefore, the use of natural gas was determined to be LAER for each gasifier preheater.

The use of a low sulfur fuel, restricted operating conditions, and good combustion practices were also selected as BACT for each of the two gasifier preheat vents. The following are the proposed BACT/LAER emission rates for each gasifier preheater:

Table 19.15: Gasifier Preheater BACT/LAER Analysis Summary

Pollutant	Proposed BACT/LAER	Proposed BACT/LAER Emission Limits (emission limits are per gasifier preheater)	
NO_x	Natural Gas Fuel Restricted Operation (startup only) Good Combustion Practices	NO_x Limit:	1.87 lb/hr (30-day ave)
SO_2		SO_2 Limit:	0.22 lb/hr (30-day ave)
CO		CO Limit:	24.7 lb/hr (1-hr ave)
VOC		VOC Limit:	1.6 lb/hr (8-hr ave)
Particulate Emissions (LAER)		Particulate Limit: (PM_{10} - filterable)	2.2 lb/hr (24-hr ave)

19.10 Emergency Generator and Fire Pump Control Technology Review

The emergency generator and fire pump are used to support emergency operations at the proposed IGCC facility. Potential emissions from each source are controlled by restricting the hours of operation, utilizing good combustion practices, and using a low sulfur fuel. Operation of both the emergency generator and fire pump will be limited to emergency operating scenarios or required testing by the manufacturer. Each will operate less than or equal to 500 hours per year. The design of both sources will incorporate manufacturer specifications that maximize the combustion efficiency and minimize potential emissions. Additionally, both sources will utilize a low sulfur diesel fuel containing less than or equal to 0.05% sulfur.

No examples were found regarding the application of LAER for particulate emissions associated with emergency generator or emergency fire pump operations. The potential particulate emissions from both sources are negligible (<0.2 tons/year PM_{10} filterable from the emergency fire pump and <0.4 tpy PM_{10} filterable from the emergency generator). Therefore, the use of restricted operations, good combustion practices, and low sulfur fuel were determined to be LAER for the emergency generator and fire pump.

Good combustion practices, restricted annual operations, and low sulfur fuel have also been selected as BACT. The following are the proposed BACT/LAER emission rates for the emergency generator and fire pump:

Table 19.16: Emergency Generator BACT/LAER Analysis Summary

Pollutant	Proposed BACT/LAER	Proposed BACT/LAER Emission Limits (emission limits are per gasifier preheater)	
NO_x	Restricted Operation (≤500 hrs/yr) Low Sulfur Fuel (≤0.05% Sulfur) Good Combustion Practices	NO_x Limit:	28.6 lb/hr (30-day ave)
SO_2		SO_2 Limit:	0.9 lb/hr (30-day ave)
CO		CO Limit:	12.1 lb/hr (1-hr ave)
VOC		VOC Limit:	1.5 lb/hr (8-hr ave)
Particulate Emissions (LAER)		Particulate Limit: (PM_{10} - filterable)	1.5 lb/hr (24-hr ave)

Table 19.17: Emergency Fire Pump BACT/LAER Analysis Summary

Pollutant	Proposed BACT/LAER	Proposed BACT/LAER Emission Limits (emission limits are per gasifier preheater)	
NO_x	Restricted Operation (≤500 hrs/yr) Low Sulfur Fuel (≤0.05% Sulfur) Good Combustion Practices	NO_x Limit:	13 lb/hr (30-day ave)
SO_2		SO_2 Limit:	0.9 lb/hr (30-day ave)
CO		CO Limit:	2.8 lb/hr (1-hr ave)
VOC		VOC Limit:	1.1 lb/hr (8-hr ave)
Particulate Emissions (LAER)		Particulate Limit: (PM_{10} - filterable)	0.9 lb/hr (24-hr ave)

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Appendix B

Air Quality

B-1 BACT Analysis
B-2 Cooling Tower Analysis
B-3 Emission Calculations

Appendix B-1

BACT Analysis

APPENDIX B-1
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

In Washington, Best Available Control Technology BACT is required for criteria and toxic air pollutant (TAP) emissions from new and modified industrial sources. This Appendix presents a BACT analysis for emission units associated with the PMEC. The basis for the emissions-related analyses is annual average operation at a design capacity of nominally 600 gross megawatts (MW). The proposed PMEC as currently configured will involve the following major processes and emission units:

- Two Syngas-Fired Combustion Turbines;
- Two Heat Recovery Steam Generators (HRSG) and two Steam Turbine-generator;
- Two 6-cell, Recirculating, Mechanical-draft Cooling Towers for the combined cycle plants;
- One 7-cell Recirculating, Mechanical-draft Cooling Tower for the Air Separation Unit;
- One Auxiliary Boiler
- Solid Feedstock Receiving and Handling (railcar and ship facilities, feeding two storage domes)
- Gasification Plant, including Enclosed Flare
- Slag Handling System
- Syngas Cleanup Processes
- Tank Vent Oxidizer System
- Emergency, Diesel Engine-Driven Generator and Fire Water Pump

B-1.1 BACT ANALYSIS OVERVIEW AND RESULTS SUMMARY

The proposed BACT controls and associated emission rates for each emission unit are summarized in Table B-1-1. Project sources addressed in this table include:

- Combustion turbines
- Railcar solid feedstock unloading to storage bins
- Ship solid feedstock unloading to storage bins
- Feedstock preparation plant (handling systems, rod mill)
- Sulfur recovery unit
- Gasification island flare
- Tank vent collection and boiler system
- Auxiliary boiler

- Cooling towers
- Emergency diesel engines

The IGCC process converts fossil fuel feedstock (petroleum coke, coal, or a combination) into a synthesis gas (syngas), which then can be used to fuel combustion turbines to generate electricity. Figure 2.3-1 of this Application provides an illustration of the proposed PMEC complex indicating the layout of the major plant components within the site.

In this application Energy Northwest is proposing the installation of Selective Catalytic Reduction (SCR) as an (Innovative Control Technology) ICT (defined in 40 CFR 52.21(b)(19)), which surpasses EPA established BACT NO_x control at IGCC facilities. This will be the first proposed installation in the western United States of post-combustion add-on emission controls on syngas-fired combustion turbines. While SCR is commonly used to limit NO_x emissions from natural gas-fired combustion turbines, no prior New Source Review (NSR) permits for IGCC facilities have specified this or any other post-combustion control technology as BACT for NO_x. The explanation for this history is the potential for adverse effects of syngas combustion products on the SCR catalyst and other technical barriers to SCR implementation at IGCC power plants. SCR may only be considered as technically feasible at a cost level much higher than is acceptable for BACT-based emission limits, and as noted above, its performance has never been demonstrated for turbines at an IGCC plant. Petroleum coke (petcoke) or coal-derived syngas is sufficiently different in composition compared to natural gas that SCR cannot be assumed to provide reliable NO_x emissions control without very high additional expenditures to remove sulfur and other contaminants from the syngas fuel. PMEC plans to accomplish this through the addition of a Selexol ® or equivalent system

TABLE B-1-1
PROPOSED BACT FOR THE PMEC

Pollutant	Control	Emissions Limits
IGCC Combustion Turbines (Emissions shown per combustion turbine excluding Start up / Shutdown conditions). All values in lb/MMBtu are based on fuel energy input of feedstock to the gasifiers.		
NO_x	Diluent Injection (BACT Limit)	15 ppm NOx @ 15% O_2 on syngas gas fuel, 3-hour average
		25 ppm NOx @ 15% O_2 on natural gas fuel, 3-hour average
	Selective Catalytic Reduction (ICT Limit)	3 ppm NOx @ 15% O_2 on syngas gas fuel, 3-hour average
		5 ppm NOx @ 15% O_2 on natural gas fuel, 3-hour average
CO	Good Combustion Practices (GCP)	15 ppm @ 15% O_2 (above 50% load) 3-hour average
PM/PM_{10}	GCP, gas cleanup, Gaseous Fuels only	0.009 lb/MMBtu heat input to gasifier

Table B-1-1 (Continued)
Proposed BACT for the PMEC

Pollutant	Control	Emissions Limits
SO_2	Gas cleanup (BACT Limit)	50 ppmvd H_2S in undiluted, unsaturated syngas, rolling 30-day average
	Selexol® Gas Cleanup (ICT limit)	10 ppmvd H_2S in undiluted, unsaturated syngas, rolling 30-day average,
VOC	GCP	0.003 lb/MMBtu heat input to gasifier
NH_3	Molar ratio control on Injection Sys.	5 ppmvd @ 15% O_2 (ammonia slip), 20 lb/hr (ICT-based Limit)
H_2SO_4	Gas cleanup/ Limit on reduced sulfur in syngas	3.2 lb/hr, 13.83 tpy (10 ppm S)
Mercury	Syngas Cleanup Process	0.0033 lb/hr
Railcar Unloading Building and Transfer to Storage Domes (3,186 tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.171 lb/hr
Ship Unloading Facility and Transfer to Storage Domes (1,900 tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.436 lb/hr
Storage Domes Ventilation (3,186 maximum tons feedstock per hour)		
PM/PM_{10}	Baghouse, 99% efficiency	0.085 lb/hr
Gasification Island Enclosed Flare (capacity of 3,730 MMBtu/hr as syngas) - Assumes worst-case upset (85% of max syngas capacity for gasifiers).		
NO_x	GCP	Exit velocity > 60 meters/second
CO	GCP	
PM/PM_{10}	GCP, gaseous fuel only	
SO_2	GCP, Gas cleanup/Limit on reduced sulfur in syngas	Natural gas purge Steam or air assisted flare design
VOC	GCP	
Tank Vent Collection System and Vapor Processing Unit		
NO_x	GCP, low-NOx burner	0.3 lb/MMBtu fired, 3-hr average
CO	GCP	0.09 lb/MMBtu fired, 3-hr average
PM/PM_{10}	GCP, gaseous material only	0.01 lb/MMBtu fired, 3-hr average
SO_2	Gas cleanup/Limit on reduced sulfur in syngas	5.8 lb/hr SO_2 (1-hour average) 4.2 llb/hour SO_2 (24-hour average)
VOC	GCP	0.004 lb/MMBtu fired, 3-hr average
Auxiliary Boiler (Natural Gas-Fired, 130 MMBtu/hr heat input)		
NO_x	GCP, low-NOx burner	0.036 lb/MMBtu fired, HHV, 3-hr average
CO	GCP	0.074 lb/MMBtu fired, HHV, 3-hr average
PM/PM_{10}	GCP, natural gas fuel only	0.005 lb/MMBtu fired, HHV, 3-hr average
SO_2	GCP, natural gas fuel only	0.00286 lb/MMBtu fired, HHV 3-hr average
VOC	GCP, natural gas fuel only	0.004 lb/MMBtu fired, HHV, 3-hr average

Table B-1-1 (Continued)
Proposed BACT for the PMEC

Pollutant	Control	Emissions Limits
Cooling Towers (2, 6-cell, Mechanical Draft Type)		
PM/PM_{10}	High Efficiency Mist Eliminators, TDS limit in circulating water	0.0010% draft as percent of circulating water
Emergency Diesel Engines (1, 300 hp firewater pump; 1, 2-MW, 2682 hp generator) - assumes 100 hours per year normal maintenance operation per engine.		
NO_x	Combustion controls, restricted operating hours	Operatons limited to < 100 hours/year Use of low-sulfur (0.05 weight percent) diesel fuel.
CO	Combustion controls, restricted operating hours	
PM/PM_{10}	Combustion controls, restricted operating hours, low-sulfur diesel fuel	
SO_2	Low-sulfur diesel fuel, restricted operating hours	
VOC	Combustion controls, low-sulfur diesel fuel, restricted operating hours	

The following sections describe the BACT demonstration process, the unique characteristics of IGCC and syngas that affect facility emissions, and the individual control technology evaluations for each emission unit and pollutant subject to BACT-based limits. Important information is provided comparing the BACT-based limits proposed for NO_x and the alternative limits that are based on adoption of an ICT for the PMEC.

This BACT analysis accounts for combustion turbine unit and syngas clean-up startup cycles, as well as normal operations of this equipment. There will be higher transient emission rates for NO_x, CO and VOC during each turbine start-up event than during normal turbine operations. This is explained by decreased fuel combustion efficiency during the early stages of a startup event and exhaust temperatures that will initially be below the lower end of the SCR operating range. Accordingly, the total annual emissions have been calculated throughout this Application with a conservative assumption of 50 hours of startup operating mode per turbine per year, with normal turbine operations at 100% of capacity for the remaining hours of the year. In practice, a more realistic capacity factor of 90% or less is more likely to occur.

To evaluate BACT for the emission units at an IGCC plant, it is important to understand the IGCC process. Detailed process descriptions for the proposed facilities are given in the main body of this Application. In addition, Section B-1.3 gives a general overview of the regulatory mechanism and requirements for adopting an ICT as part of a New Source Review permit. Sections B-1.4 and B-1.5 provide background on existing or proposed IGCC facilities in the United States, their expected emission levels, and the unique characteristics of this process that must be considered in a BACT evaluation.

B-1.2 BACT REVIEW PROCESS

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs" [40 CFR 52.21(b)(12)]*

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps described below (from the EPA's Draft New Source Review Workshop Manual, 1990)[1]:

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

Formal use of these steps is not always necessary. However, EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the "maximum degree of emissions reduction."

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[1] "New Source Review Workshop Manual", DRAFT October 1990, EPA Office of Air Quality Planning and Standards

Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each source. These options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams' physical and chemical characteristics.

For this BACT analysis, the available control options were identified by querying the EPA RBLC and by consulting available literature on control options for IGCC. The analysis also involves review of currently permitted and operating IGCC facilities.

B-1.3 INNOVATIVE CONTROL TECHNOLOGY PROVISIONS

The Washington Department of Ecology (Ecology) air quality regulations have incorporated by reference the federal definition of ICT, as it relates to emission controls adopted as part of a PSD permit. EFSEC, in turn, has adopted by reference virtually all the provisions of WAC 173-400, including the section related to ICT. To utilize these provisions, a new major source may request that EFSEC approve the implementation of an air pollution control system as an ICT, including special conditions regarding a demonstration phase to achieve effective control. The definition of ICT, as referenced by Washington Administrative Code (WAC) 173-400-720 (4)(a)(v), is provided in Title 40, Part 52 of the Code of Federal Regulations:

> *"...any system of air pollution control that has not been adequately demonstrated in practice but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice, or of achieving at least comparable reductions at lower cost in terms of energy, economics, or non-air quality environmental impacts." [40 CFR 52.21(b)(19)]*

Adoption of an ICT as part of a project includes conditional permit limits that are typically more stringent than BACT-based limits. However, the ICT limits do not completely replace the role of BACT in the new source's permit. The BACT-based limits for the source are still included in the new source's permit in the event that the more stringent levels anticipated for the ICT are not achieved in practice. The ICT-based limits also do not, by their inclusion in the permit, represent a more stringent BACT determination for the affected source category.

In a practical sense, several conditions must be met before the Department can approve the installation of an ICT in conjunction with issuing or revising an air quality permit. These conditions are:

1. The source demonstrates that the proposed control system would not cause or contribute to an unreasonable risk to public health, welfare, or safety in its operation or function.

2. fThe source agrees to a level of continuous emissions reduction equivalent to that which would have been required as a BACT limit by a date specified in the permit or permit revision.

3. Before the date specified in the permit or permit revision, the new source must be able to demonstrate that the achieved emissions (with or without ICT) would not:

    a. Cause or contribute to any violation of an applicable state ambient air quality standard; or

    b. Impact any area where an applicable increment is known to be violated.

4. All other applicable requirements for adoption of the PSD permit conditions, including those for public participation and regional EPA approval, have been met.

A recent precedent in which Ecology included ICT-based limits and related provisions is the PSD permit issued on August 2004, Permit Number PSD-04-01, to the Kennewick Fertilizer Operations (KFO) of Agrium U.S. Inc. for modification of emissions controls on nitric acid plants at their facility in Kennewick, Washington. This permit included a schedule of ICT-based emission rate milestones to be demonstrated for KFO Plant 9. In effect, a sequence of decreasing daily NO_x emission rate milestones (in units of lb/day) was established for the initial 48 months of source operation after the modification.

The PMEC proposes to implement SCR in concert with enhanced syngas cleanup with the Selexol® or equivalent® process as ICT. In the case of other proposed and permitted IGCC plants, SCR has not been deemed feasible as BACT. Only by making a sizeable investment in more complete syngas desulfurization, beyond that normally deemed BACT for SO2 emission limits, can the PMEC reasonably attempt to utilize SCR for NO_x control, thus potentially reducing NOx emissions of that pollutant by a further 80%.

There is no commercial operating experience with SCR on ICGC plants utilizing coal-derived syngas. However, there is a "substantial likelihood" that the proposed control technology package can achieve reduced NO_x emissions from combustion of syngas. The primary uncertainties, which are substantial, relate to several factors, including system reliability, performance at all operating conditions, reduced catalyst service life, and elevated operating costs. The proposed final ICT NO_x emission limits are shown in Table B-1-1 for the IGCC combustion turbines. Further, as shown below, the proposed PMEC using Selexol® or equivalent with SCR meets each of the previously stated criteria for treatment as an ICT:

1) Both the Selexol® systems and SCR processes are well-established at refineries, utility generating plants, and for larger gas preparation / combustion sources in other industries. Handling and bulk storage of an ammonia solution is necessary to provide a reagent to facilitate the SCR reactions that convert NO_x to elemental nitrogen, but this can be accomplished safely with suitable equipment and work practice safeguards, as evidenced by the routine use of this technology on combustion turbines utilizing natural gas. When properly designed, installed and operated the Selexol®/SCR processes do not "cause or contribute to an unreasonable risk to public health, welfare, or safety."

2) Energy Northwest will agree to include in the requested permit a requirement to achieve by a date-certain a continuous level of NO_x emission control that is at least as stringent as that corresponding to BACT limits for the IGCC combustion turbines.

3) Energy Northwest has supplied with this Application a suitable ambient air impact analysis that demonstrates, based on accepted dispersion models, that the new PMEC combustion turbine emissions, based on ICT limits or the alternative BACT-based limits, will not cause or contribute to violations of an ambient air standard or PSD increment.

4) Lastly, all of the prescribed PSD permit processing requirements for adoption of the ICT and BACT based limits will be met, including public participation and EPA Region 10 review.

The analysis to establish the alternate NO_x emission limits from the PMEC combustion turbines has been included in Section B-1.7.1, in order to support the BACT-based limits that must also be included in the requested PSD permit. In developing the requested permit, Energy Northwest intends to work with EFSEC to establish a reasonable set of demonstration milestones and a timetable for ICT implementation. It is anticipated that the ICT criteria in the permit could also be based on observed system reliability. To illustrate, if there is evidence after a sufficient test period that the use of Selexol® or equivalent and SCR will not be capable of reliably achieving the ICT limits described above, then some relaxation of these limits will be warranted. Dispersion modeling presented in this application demonstrates that compliance with applicable Washington and National Ambient Air Quality Standards and PSD increments would continue to be achieved, even in the extremely unlikely event that the proposed ICT NO_x control package provided no emission reduction beyond BACT-level controls.

B-1.4 PROJECT SOURCES SUBJECT TO BACT ANALYSIS

To evaluate possible emission control technologies, it is first important to understand the unique IGCC process and the supporting ancillary plant processes. The process descriptions for the various processes that make up the PMEC are included in Chapter 2 of this Application. The PMEC will consist of several facilities/systems representing sources of regulated air pollutants that are addressed in this BACT analysis:

- Combined Cycle Combustion Turbine Generators (Two Units)
- Railcar Solid Feed Stock Unloading and Transfer Points
- Ship Solid Feed Stock Unloading and Transfer Points
- Solid Feed Stock Storage Dome Vents
- Gasification Island Flare
- Tank Vent Collection and Boiler System
- Auxiliary Boiler (One Unit)
- Cooling Towers (two 6 and one 7 cell units)
- Emergency Diesel Engines (Generator and Fire Water Pump)

B-1.5 CONSIDERATION OF ALTERNATIVE GENERATING TECHNOLOGIES

This section addresses recent guidance relating to the need for consideration of alternative electrical generating technologies for the proposed project, as part of the BACT analysis. Compared to Pulverized Coal (PC)-fired Boilers and Circulating Fluidized Bed (CFB) Boilers, the proposed IGCC process is indeed the very lowest emitting solid fuel-based electricity generating technology available, and selection of a completely different solid fuel-based generating technology would not result in lower emissions. Later portions of this BACT analysis address the specific controls that are proposed to minimize the emissions from the proposed IGCC process.

As introduced in Section B-1.2, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions of the source and pollutant under evaluation. The most common control technologies considered in a BACT analysis are add-on control measures and inherent process characteristics that minimize generation of pollutants. Additionally, it is sometimes possible to modify the production process or work practices to improve the emissions performance of a proposed project. These types of process modifications/measures, when applicable, are properly considered in a BACT analysis. In contrast, consideration of alternatives that would involve completely "redefining the design" of the proposed process are not required to be considered (1990 Draft New Source Review Workshop Manual, Section IV.A.3). Alternative generating processes, such as natural gas-fired combined-cycle plants, represent a completely different family of power generation plant designs from IGCC. While there are certain types of components in common, such as cooling towers and steam-driven turbine generators, the technical basis for a gas-fired plant differs markedly from that of the IGCC facility.

Since CFB or PC boilers or a natural gas-fired electrical generating plant would be completely different processes, and represent "redefining the design" compared to IGCC, it is reasonable to conclude that EPA would not require that the BACT analysis for PMEC compare these different technologies. This point was recently reinforced in a December 13, 2005 letter from Stephen Page, Director of EPA's OAQPS, to E3 Consulting, LLC regarding BACT requirements for proposed coal-fired power plant projects. In that letter, EPA clarified that a BACT analysis need not consider an alternative "which would wholly replace the proposed facility with a different type of facility."

The remainder of this BACT analysis describes the various emission control options for specific IGCC facility processes, and demonstrates that the proposed PMEC would achieve the lowest emissions rate technically and economically feasible for such a facility.

B-1.6 EXISTING AND PERMITTED IGCC FACILITIES

For this BACT analysis, the available control options were identified by querying the RBLC database and by consulting available literature on control options for IGCC. Applications and/or permits from a number of other IGCC facilities that have completed the New Source Review process were also reviewed to provide additional reference material for this BACT analysis. A brief summary of the other permitted IGCC plants in the United States and their emissions limits is presented in this section.

Other existing or permitted IGCC facilities include the following examples:

- SG Solutions, Wabash River Generating Station, West Terre Haute, Indiana (operating);
- Tampa Electric Company, Polk Power Station, Mulberry, Florida (operating);
- Global Energy, Inc.'s Kentucky Pioneer Energy LLC, Trapp, Kentucky (permitted/not constructed);
- We Energies, Elm Road Generating Station, Wisconsin (permitted/not constructed);
- Global Energy, Inc.'s Lima Energy Company, Lima, Ohio (permitted/not constructed);
- Steelhead Energy Center, Southern Illinois Clean Energy Center
- ERORA Group, Taylorville Energy Center

The air permits, BACT analyses and additional literature for each of these existing or proposed facilities and several other proposed IGCC plants that have yet to complete permitting were reviewed. Each facility is discussed briefly below and Table B-1-3 summarizes the criteria pollutant emission levels permitted for the combustion turbines units at each facility. The facilities that were subject to BACT determinations are listed as such.

Wabash River Generating Station and PSI Combined Cycle Power Station: The DOE and a Joint Venture formed in 1990 between Destec Energy Inc. and Public Service of Indiana (PSI) initiated the Wabash River Coal Gasification Repowering Project. The gasification island includes an E-Gas (originally developed by Dow Chemical and known earlier as Destec Technology, and now operated by SG Solutions) two-stage, oxygen blown gasifier with full heat recovery that is integrated with the power block. This facility has been operated since 1995.

Tampa Electric Company - Polk Power Station: The DOE partly funded the Polk Power Station IGCC project. The facility includes a Texaco (now GE Energy) oxygen blown gasifier with full heat recovery using both radiant and convective syngas coolers. The GE STAG-107FA power block integrates process syngas, steam, and nitrogen. This IGCC facility has been operating since 1996.

Global Energy - Kentucky Pioneer Power Station: Global Energy USA (Global), owner of Kentucky Pioneer Energy, LLC, negotiated with the DOE and Clean Energy Partners, LP to acquire a conditionally approved IGCC Demonstration Project. The British Gas/Lurgi (BG/L) slagging fixed-bed gasification technology has been proposed in a new 540 MW (net) IGCC facility using both coal and refuse derived fuel as a feedstock. The gasification system would be coupled with Fuel Cell Energy, Inc.'s molten carbonate fuel cell. The air permit for this facility was originally issued in June 2001, and has been extended conditioned on revision of the BACT Analysis; this project is not expected to go forward.

Global Energy - Lima Energy Power Station: Lima Energy Company, a Global Energy company, obtained a final Ohio EPA Permit to Install an IGCC facility in Lima, Ohio. The 540 MW (net) IGCC is expected to use ConocoPhillip's E-Gas entrained flow gasification technology to convert high sulfur coal or petroleum coke into syngas. The air permit was issued in 2002. Construction of the feedstock storage building has begun in order to keep the PSD permit in place while Global decides on whether or not to continue the project.

We Energies - Elm Road Generating Station: We Energies recently proposed a new 600 MW net nominal base-load IGCC generating unit at the Elm Road Generating Station. The facility includes a gasification plant, sulfuric acid plant, two combustion turbine generators and HRSGs, and a steam turbine generator. The permit for this facility was received in January 2004. However, commencement of construction was linked to a determination of need and further acceptance by the Public Utility Commission, which ultimately rejected We Energies' proposal to advance the project.

ERORA Group - Taylorville Energy Center: The ERORA Group is developing the Taylorville Energy Center, a 630 MW (net) IGCC facility to be located in Southern Illinois, and the similar Cash Creek Generation IGCC facility, to be located near Owensboro, Kentucky. They are proposing to use GE Energy gasification technology at both facilities, using local coals

(Kentucky coal for Cash Creek and Illinois coal for Taylorville) as the feedstocks. Both will use Selexol AGR systems, as well as SCR. Neither site is in an ozone non-attainment area, so SCR is not required for BACT purposes. ERORA is using SCR to minimize NO_x emissions from the plant, but not as BACT. This will allow them to minimize the cost to acquire NO_x allowances from the market. ERORA notes that in order to increase the chance that the SCR system will work in this unproven application on coal-derived syngas, higher sulfur removal, by using Selexol instead of MDEA, will be required. Both the Taylorville and Cash Creek applications are under agency review.

Steelhead Energy: Southern Illinois Clean Energy Center This proposed facility will incorporate IGCC with co-production of synthetic natural gas (SNG). The 544 MW (net) facility is proposed to consist of an IGCC plant that will provide syngas to two combustion turbines, with additional syngas being processed in a methanation facility to produce SNG. The primary feedstock for the facility will be Illinois #6 bituminous coal from an adjacent mine. The IGCC facility will consist of two ConocoPhillips gasifiers with syngas cleanup, sulfur or sulfuric acid plant and mercury removal systems. The primary fuel for the combustion turbines will be syngas from the IGCC unit. Natural gas from the SNG unit will be available for startups and as a backup fuel. According to discussions with State of Illinois EPA staff, this project may be relocated to another site, and may only include SNG production, without IGCC power production.

TABLEB-1-3
PERMITTED EMISSION RATES FOR IGCC UNITS

In lbs/MMBtu gasifier fuel energy input (approximate) Location	MMBtu/hr as coal to gasifier or Plant MW (estimated)	CO	NOx	SO_2	PM	VOC
Wabash River (operating)	2,356	0.036	0.087	0.126	0.005	0.001
Polk Power Station (operating)	2,191	0.045	0.101	0.170	0.008	0.001
Kentucky Pioneer	4,413	0.026	0.059	0.026	0.009	0.004
Lima Energy	4,413	0.035	0.067	0.022	0.008	0.007
We Energies	5,424	0.024	0.059	0.023	0.008	0.003
Steelhead Energy Center	544 MW	0.04	0.059	0.033	0.0092	0.0029
Taylorville Energy Center	677 MW	0.036	0.058	0.045	0.007	0.008
PMEC Proposed IGCC	600	0.036	0.012 (3- hr, ICT)	0.016 (3-hr, ICT)	0.0010	0.003

The emission rates listed in Table B-1-3 have been estimated based on permit documents or other published information on the respective facilities and converted to the units of lbs per million Btu of gasifier feedstock, for the purposes of general comparison. The actual permitted levels and/or BACT determination in many cases are expressed in units different than lbs/MMBtu, and may be expressed on the basis of MMBtu input of syngas fuel to the combustion turbines rather than MMBtu to the gasifier (the correct basis). The conclusion to be drawn from this comparative review is that proposed BACT limits for the PMEC are similar to, or more stringent than, those that have been accepted in other recent IGCC permits throughout the United States.

In addition to the units listed in the table above, OUC and Southern Power Company have proposed a nominal 285 Megawatt (net) IGCC Unit (Stanton Unit B) and auxiliary equipment. Unit B will consist of: an air-blown coal gasification system that produces syntesis gas (syngas); one syngas and natural gas-fired General Electric 7FA+e combustion turbine-electrical generator (CT); a duct burner within a supplementary-fired heat recovery steam generator (HRSG); a steam turbine electrical generator (STG); an exhaust stack and a multi-point ground flare. The project was selected by the Department of Energy for funding under Round 2 of the Clean Coal Power Initiative. A Preliminary Determination and draft construction permit for this project were issued by the Florida Department of Environmental Protection Division of Air Resource Management in the summer of 2006.

The IGCC process represents a unique generating technology with promises of increased efficiency, fuel flexibility, low emissions, and opportunities for carbon sequestration. However, it is relevant to note that while there has been significant interest in IGCC facilities, few projects permitted in the past several years have moved substantially forward. The lack of progress toward widespread commercialization of this promising technology is due largely to the fact that the first generation of IGCC plants has incurred significant financial and operational risks. This burden is significant and should be considered in the determination of required emissions controls, particularly if the use of higher levels of controls or unproven methods might add significantly to the costs, reliability or other operational risks of the PMEC.

B-1.7 COMBUSTION TURBINE BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the combustion turbines of the proposed PMEC to determine appropriate BACT emission limits. This BACT analysis is based on the current state of IGCC technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

B-1.7.1 NITROGEN OXIDES BACT ANALYSIS

The criteria pollutant nitrogen oxides (NO_x) is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Syngas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is expected that essentially all NO_x emissions from the PMEC combustion turbines will originate as thermal NO_x.

As noted in Section B-1.4 of this Appendix, an IGCC combustion turbine is an inherently low-emitting process. The proposed PMEC combustion turbines can nominally achieve 0.06 lb/MMBtu using diluent injection (i.e., without SCR). The remainder of this analysis considers the use of this lower-emitting IGCC process in conjunction with add-on controls that eliminate emissions after they are produced by fuel combustion in the turbines.

The rate of formation of thermal NO_x in a combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature. Front-end NO_x control techniques are aimed at controlling one or more of these variables during combustion. Examples include diluent injection (steam, water, or nitrogen) and dry low-NO_x burners. These technologies are considered to be commercially available pollution prevention techniques. It is necessary to recognize the fundamental differences between natural-gas fired and syngas-fired combustion turbines in evaluating these techniques. Compared to natural gas, syngas has a much higher hydrogen content (natural gas is often over 90% methane), and a much lower heating value (about 250 Btu/scf for syngas vs. 1,000 Btu/scf for natural gas). Also, the pretreatment of the syngas includes a moisturization step which increases the content of water vapor in the gas. Taken together, these differences alter the combustion kinetics of the burner flame in a manner that prevents the use of lean-premix combustion techniques, which are the defining feature of effective Low-NO_x burner design [2].

B-1.7.1.1 Identify Control Technologies

Possible control technologies for the proposed turbines were identified by examination of previous IGCC permits and through RBLC queries for natural gas-fired combined cycle (NGCC) combustion turbines. All previous BACT and LAER determinations for IGCC facilities have resulted in the finding that diluent injection represents the best available control for NO_x. However, for this top-down analysis, all of the following technologies were considered to be potentially available for the PMEC combustion turbines:

Combustion Process Controls

- Dry Low NO_x burners
- Diluent injection (nitrogen or steam)

Post-Combustion Controls

- SCONO$_x$™
- SCR
- Selective non-catalytic reduction (SNCR)

B-1.7.1.2 Evaluate Technical Feasibility

Each identified technology is first examined to determine if it is technically feasible for IGCC combustion turbines burning coal-derived syngas. First, controls potentially achieved by modifications to the combustion process itself are considered. Next, potential control methods utilizing add-on control equipment, such as SCR, to remove NO_x from the exhaust gas stream after its formation during combustion are examined.

Dry Low NO_x Burners

Dry Low-NO_x (DLN) burners control NO_x formation in conventional Natural Gas Combined Cycle (NGCC) combustion turbines by staged combustion of the natural gas. This is done by

[2] "Major Environmental Aspects of Gasification-Based Power Generation Technologies", U.S. DOE, Office of Fossil Energy, National Energy Technology Laboratory, December 2002.

designing the burners to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual burner's flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Syngas differs from natural gas in heating value, gas composition, and flammability characteristics. Existing DLN burner technologies available for combustion turbines were designed for natural gas (methane-based) fuels and will not operate on the syngas (H_2/CO-based) fuels utilized by IGCC combustion turbines. DLN combustors are not technically feasible for this application due to the potential for explosive mixtures in the combustion section due primarily to the high hydrogen content of the syngas. No manufacturer currently makes DLN burners that can be used for a combustion turbine burning petroleum coke or coal-derived syngas. Combustion turbine vendors are currently researching DLN for syngas-fueled combustion turbines, but such combustors are not yet commercially available. Therefore, DLN burners are not a technically feasible control option for this unit.

Diluent Injection

The addition of an inert diluent such as atomized water or nitrogen into the syngas before combustion, and/or steam or nitrogen injection into the high temperature region of a combustor flame serves to inhibit NO_x formation by reducing the peak flame temperature. For the PMEC, the syngas will be diluted with nitrogen and moisturized to condition it for use in the combustion turbine. This effectively lowers the fuel heat content and, consequently, the combustion temperature, and therefore reduces NO_x emissions. Another level of this control option is steam injection directly into the combustion zone to cool temperatures and reduce NO formation. Diluent injection can achieve emission levels of 15 ppmvd NO_x (at 15 % oxygen) when firing 100% syngas. A secondary benefit of diluent injection is that it will increase the mass flow of the exhaust and, thus, the power output per unit of fuel input also increases. It is important to note that the best performance achievable for combustion turbines that are optimized for syngas is 25 ppm NOx when they are firing natural gas.

Diluent injection represents an inherently lower-emitting process for IGCC units, and is a technically feasible control technology. Diluent injection (water vapor and nitrogen) during the conditioning of the syngas is proposed as the BACT limit basis for the PMEC combustion turbines. This option will achieve NO_x levels of 15 ppmvd (at 15% O_2) over a 3-hour average (excluding start up, shutdown and upset periods), and is proposed as the baseline case for the IGCC combustion turbine NO_x BACT analysis. This NO_x control technology and emission level have also been determined as BACT for all other recent IGCC permits.

SCR

SCR is a technology that achieves post-combustion reduction of NO_x from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a specialized catalyst module, promoting conversion of NO_x to molecular nitrogen. The hardware of an SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), the structured, fixed-bed catalyst module, and electronic controls. This is an increasingly common control technology for use on NGCC combustion turbines. However, the design conditions and performance concerns are different for each technology, and a single SCR design is not generally transferable from one generating technology to another.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the NH_3 reacts with NO_x to form molecular nitrogen and water. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

A fixed-bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_x decomposition to occur. In natural gas turbine, NO_x removal of 90 percent or higher is theoretically achievable at optimum conditions. Key SCR performance issues focus on flue gas characteristics (temperature and composition), catalyst design, and ammonia distribution. Certain compounds such as sulfur and certain metals, if present in the exhaust gas stream, can "poison" the catalyst, reducing its performance and useful life, impact catalyst activity, or inhibit conversion efficiency.

The typical effective temperature range for base-metal SCR catalysts is 600 to 800°F. If the exhaust gas temperature drops below 600°F, the reaction efficiency becomes too low and increased amounts of NO_x and NH_3 will be released out the stack to the atmosphere. The exhaust temperature after the heat recovery steam generator (HRSG) in a combined cycle unit will be only about 250°F. Since this temperature is too low for the SCR reactions to occur, SCR catalyst would need to be located upstream of the HRSG where the exhaust gas temperature conditions are favorable.

The most significant SCR feasibility issue for this project is the fact that the syngas contains reduced sulfur compounds, even after the high-efficiency sulfur recovery proposed for the PMEC plant. These drawbacks are reduced, but not eliminated, by the utilization of Selexol® technology for additional sulfur removal to the extent practical. After combustion, some of the oxidized sulfur will form ammonium-sulfur salts in the presence of the ammonia reagent that can impact the SCR catalyst and equipment downstream.

This path of fuel sulfur through the process starts with oxidation of syngas sulfur during combustion, primarily to SO_2 and also a small fraction to SO_3. If SCR were installed, the vanadium in the SCR catalyst would oxidize additional amounts of the SO_2 in the flue gas to SO_3. Adsorption of these sulfur oxides can deactivate the catalyst reaction sites, tending to shorten the effective catalyst service life. In addition, some of the NH_3 reagent injected upstream of the catalyst will react with the available vapor phase SO_3 to form ammonium sulfate and ammonium bisulfate salts. These salts will largely remain in the vapor phase at the elevated temperature of the SCR system. However, as the exhaust gas cools in the HRSG and further downstream, the gas will drop below the sublimation temperature of these compounds and they will begin to precipitate out, forming corrosive, sticky particles. Accumulation of these salts can cause serious corrosion and plugging/fouling problems in a conventional HRSG, as well as a loss of heat transfer efficiency, even at the relatively low levels of sulfur present in the syngas.

As deposits of ammonium salts increase, they would need to be cleaned periodically from the surface of the HRSG heat transfer fins in order to restore heat transfer efficiency and pressure within the HRSG. The PMEC is incorporating specific design features in the HRSG to facilitate such cleaning, as necessary, downstream of the SCR module. Absent costly design features, adequate cleaning of the heat transfer fins is difficult in a conventional HRSG because of the following:

- Access to interior tube banks is restricted in a compact HRSG module;
- Excessive capital cost and potential for leakage would be encountered if the HRSG heat exchange elements were designed for removal/replacement; and
- The HRSG is in close proximity to upstream catalyst modules; power washing of the HRSG would increase the possibility of inadvertently flooding the fixed-bed catalyst, which would damage it.

The other main feasibility issue with SCR on IGCC units is the potential presence of trace metals and other trace compounds in syngas, which are known to deactivate the sensitive SCR catalyst. For example, arsenic is known to deactivate certain types of catalyst, and the deactivation rate can vary in the presence of other compounds, such as calcium. Research is ongoing to understand how individual and various combinations of flue gas constituents may impact catalyst deactivation rates and performance. Because no full-scale IGCC unit has been tested or operated with SCR in a coal-derived syngas environment, many unknowns remain regarding the potential impacts of trace constituents such as arsenic, nickel, lead, and cadmium. Consequently it is difficult to predict SCR system performance, control efficiency, or catalyst life for this unique application. These uncertainties reinforce the need for SCR to be considered an ICT, as described previously.

There is a growing experience base of SCR use on conventional PC units that seem to suggest that SCR should work in the seemingly less extreme exhaust conditions of an IGCC combustion turbine. However, many key process parameters are different in an IGCC versus a PC unit, and these differences may significantly impact SCR's feasibility, cost, design, and performance in this unique service environment. Key differences for an IGCC compared to a PC plant SCR system application include the following:

- SCR performance expectation in conventional PC unit service is significantly lower (i.e., higher outlet NO_x) than would be needed in this case. PC-based SCR systems typically achieve about 0.07-0.10 lb NO_x/MMBtu with SCR, which is greater than the PMEC proposed level (nominally 0.06 lb/MMBtu for a 3-hour average) without any add-on controls.

- Ammonium bisulfate salts may form in a PC unit air preheater, which is of a very different design from a HRSG. Air preheaters can be designed to accommodate more frequent cleaning, and are thus better-suited to handling precipitation/deposits/corrosion. Air preheater heat transfer baskets are not impacted as much by corrosion as the heat transfer fins in a HRSG.
- Ammonia preferentially adsorbs onto the fly ash produced from a PC unit, so that sulfates and bisulfate can be captured in downstream particulate matter control equipment.

Recent papers by EPA[3] and DOE[4] recognize the challenges associated with the application of SCR to IGCC. These concerns are well-known and validated in the technical literature, and raise legitimate questions regarding the practicality of SCR for this (or any other) IGCC project. However, Energy Northwest proposes to adopt this aggressive control technique along with additional syngas sulfur cleaning as an ICT. This option must be viewed as an enhanced level of emission control that is more stringent than BACT. As explained at the end of Section B-1.2 of this Appendix, EPA does not consider a technology "available" until it has reached commercial availability for the intended service. While SCR is clearly an "available" technology that is commercially demonstrated for many applications, SCR is only at the "concept stage" for IGCC. EPA's New Source Review Workshop Manual[5] specifically states that "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

The question of SCR feasibility in IGCC service has been addressed recently by several other proposed projects and their state and regional environmental agencies. Polk Power Station in Florida, Kentucky Pioneer LLC in Kentucky, Lima Energy LLC in Ohio, and We Energies in Wisconsin have all finalized or updated BACT determinations for their IGCC projects. The state environmental agencies in Florida, Kentucky, Ohio, and Wisconsin, along with US EPA Regions IV and V, have determined BACT for those IGCC projects to be 15 ppm NO_x @15% O_2 using diluent injection (when firing syngas). In each case, SCR was rejected as BACT. This finding is consistent with recent previous BACT determinations for IGCC units using solid feedstocks such as petroleum coke and/or coal.

In summary, SCR has never been employed at an IGCC facility using a solid feedstock such as coal or petroleum coke. No previous BACT determination has found SCR to be technically feasible and economically feasible on an IGCC. On this basis, PMEC is requesting that the adoption of SCR in conjunction with an enhanced level of Selexol® or equivalent-based syngas sulfur removal, be treated as an ICT for purposes of incorporating permit conditions that allow a sufficient incremental timeframe for technology demonstration and final determination of NO_x

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[3] "Environmental Impact Comparisons IGCC vs. PC Plants", Kahn, Wayland, and Schmidt of US EPA, presented at Pittsburgh Coal Conference, September 2005.
[4] "Major Environmental Aspects of Gasification-Based Power Generation Technologies", U.S. DOE/NETL, December 2002
[5] Pg. B-12, "New Source Review Workshop Manual" Draft 1990, EPA Office of Air Quality Planning and Standards.

emissions. Generally accepted BACT for IGCC combustion turbines is diluent injection, and this should be identified as the basis for BACT emission limits in the PMEC permit as well.

SCONOx

The $SCONO_x$™ system is an add-on control device that reduces emissions of multiple pollutants. $SCONO_x$™ control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). $SCONO_x$™ utilizes a single catalyst for the reduction of CO, VOC and NO_x, which are converted to CO_2, H_2O and N_2. The system does not use NH_3 and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of $SCONO_x$™ requires natural gas, water, steam, electricity and ambient air, and no special reagent chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

There are currently several $SCONO_x$™ units in commercial installations worldwide, although all are on much smaller facilities than the proposed PMEC. The original installation is at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This installation is on a GE LM2500, an approximately 25 MW combined cycle system, which has had an operating $SCONO_x$™ system since December 1996. That system has undergone many changes over the years. The second commissioning of a $SCONO_x$™ system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Taurus 50 Model. This facility has reported problems with meeting permitted NO_x levels of 2.5 ppm, and subsequently received a permit modification extending the $SCONO_x$™ demonstration period. Three other units were installed in recent years, two on 13 MW Solar Titan CTs at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International airport.

There is no current working experience of $SCONO_x$™ on large combustion turbine units such as those proposed for the PMEC. Similarly, there are no applications of this technology with the fuel sulfur levels associated with IGCC combustion turbines. $SCONO_x$™ was considered at some larger applications including a 250 MW unit at the La Paloma plant near Bakersfield, and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects were given the alternative to install SCR and now plan to do so. In evaluating technical feasibility for large IGCC power stations, the additional concerns are:

- $SCONO_x$™ uses a series of dampers to re-route air streams to regenerate the catalyst. The proposed PMEC is significantly larger than the much smaller facilities where $SCONO_x$ has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the PMEC combustion turbines.
- The catalyst is very susceptible to poisoning by sulfur compounds. Because of the sulfur content of the syngas, a separate catalyst to absorb SO_2 would be required. The vendor offers a $SCOSO_x$™ catalyst; however, its operation is not proven, and upon regeneration this process would create an H_2S stream that would require treatment.

- SCONOx™ would not be expected to achieve lower guaranteed NO_x levels than SCR, and, for reasons described above, it has even greater feasibility concerns with respect to application on IGCC turbines than those for SCR

For the above reasons, SCONOx™ is considered technically infeasible for application to the PMEC combustion turbines.

SNCR

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_x control technology in which a reagent (NH_3 or urea) is injected into the exhaust gases to react chemically with NO_x, forming elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_x emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x and the NH_3 slip concentrations (NH_3 discharge from the stack) will be very high.

This technology is occasionally used in conventional fired heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been applied in IGCC service, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Because of the incompatibility of the exhaust temperature with the SNCR operating regime, this technology is considered to be technically infeasible.

B-1.7.1.3 Rank Control Technologies

Among the control technologies considered in the previous subsection, only one was determined to be both technically feasible and commercially demonstrated at a cost level acceptable as a BACT option. Specifically, the feasible option is diluent injection upstream of the combustion zone to achieve a controlled level of 15 ppmvd NO_x at 15% O_2 while firing syngas, and 25 ppmvd NO_x at 15% O_2 while firing natural gas. Table B-1-4 shows the typical NO_x control levels for the different options, in comparison with the NSPS Subpart Da limit of approximately 100 ppmv for stationary gas turbines burning syngas that are considered the BACT "floor" for this source category. In addition, a comparison with the proposed installation of SCR as an ICT is included in Table B-1-4.

During periods of firing natural gas as the start-up or back-up fuel, the combustion turbine will achieve 25 ppmvd NO_x, without the benefit of proposed ICT add-on control. This is due to the higher heating value and difference in diffusion flame speed for natural gas versus syngas. The applicant proposes to use natural gas for less than 50 hours/year for turbine startups plus up to 440 hours per year of full-load operation during transition to syngas firing. The annual emissions estimates for the combustion turbine assume this higher NO_x emissions rate for 490 hours per year (total of start up periods and full-load natural gas firing).

TABLE B-1-4
RANKING OF NO_X BACT EMISSION LIMIT OPTIONS FOR COMBUSTION TURBINES

Control Technology Option	Emissions per IGCC CT without Option1 (Tons/yr)	Emissions Reduction per IGCC CT1 (Tons/yr)	Emission Performance	Emissions per IGCC CT1 (Tons/yr)
Selective Catalytic Reduction (SCR) – ICT	725	580	3 ppmv @ 15% O2, 3-hour average (Syngas) 5 ppmv @ 15% O2, 3-hour average (Nat Gas)	145
Diluent (Nitrogen/Moisture) Injection – Proposed BACT	~ 1,520	795	15 ppmv @ 15% O2, 3-hour average (Syngas) 25 ppmv @ 15% O2, 3-hour average (Nat Gas)	725
NSPS BACT [2,]	Baseline Option	N/A	100 ppm @ 15% O_2 (Syngas)[3]	~4,800 tons

Notes:
1. Annual emissions are based on one combustion turbine firing ~490 hours per year on natural gas, and the balance on syngas at full load. (PMEC includes 2 combustion turbines)
2. Most stringent potentially applicable emission limit for the IGCC combustion turbines, from NSPS Subparts Da Syngas units without duct burners

B-1.7.1.4 Evaluate Control Options

The next step in a BACT analysis is to conduct an analysis of the energy, environmental and economic impacts associated with each feasible control technology. Based on the evaluation in the previous step, the only technically feasible and commercially proven technology suitable for establishment of BACT limits is diluent injection. The most notable environmental impact associated with this NO_x control technology is water usage. Depending on the diluent selected, this option could entail additional water usage. Approximately 25,000 gallons per hour would be used in the moisturization process for NO_x control and power augmentation. Moisturization of the syngas is expected to comprise of approximately 8-9% of total PMEC make-up water usage. The emission rate shown for this option in Table B-1-4 is based on the PMEC combustion turbines operating with nitrogen and water vapor injection into the syngas stream. Since SCR with enhanced syngas desulfurization is proposed as an ICT measure, this evaluation also addresses the energy and environmental effects of SCR.

The principal environmental consideration with respect to implementation of SCR is that, while it will reduce NO_x emissions, it will add NH_3 emissions associated with use of ammonia (NH_3) as the reagent chemical. A portion of the unreacted NH_3 passes through the catalyst and is emitted from the stack. This is called ammonia slip and the magnitude of these emissions depends on the catalyst activity and the degree of NO_x control desired. While reduction in NO_x emissions offers benefits with respect to NO_2 PSD increment consumption and conformance with the NO_2 ambient air quality standard, ammonia is listed as a Class B toxic air pollutant in Ecology regulations (WAC 173-460-160). Also, ammonia emissions contribute to the generation of aerosol species that are regional haze precursors.

As described in Section B-1.7.1.2, there are potential technical barriers to cost-effective implementation of SCR. Injection of ammonia results in formation of ammonium sulfate salts that deposit on the SCR catalyst module, and on duct and heat transfer surfaces downstream of the SCR module. Accumulation of these precipitated ammonium sulfate salts can cause corrosion and plugging/fouling problems in a conventional HRSG, as well as a loss of heat transfer, even at the relatively low levels of sulfur present in the PMEC syngas (see the discussion on the nature of these problems in Section B-1.7.1.2).

The accumulation of a layer of ammonium salts on the heat transfer fins located inside the HRSG gradually decreases the heat transfer efficiency as they become increasingly fouled with deposits. Power output from the combustion turbine can also be significantly affected due to an increase in pressure drop within the HRSG resulting from the partial blockage of gas flow by these deposits. This pressure rise can also impact HRSG casing design requirements. In addition, ammonium bisulfate is corrosive and corrodes the heat transfer fins or tubes, potentially impacting the reliability of the HRSG.

B-1.7.1.5 Select Control Technologies

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. As has been explained, for this application of syngas-fired combustion turbines within an IGCC facility, diluent injection in the combustion turbine is the appropriate control technique for setting BACT-based emission limits. The proposed BACT limits based on this technology are 15 ppmvd NOx at 15% O_2 for syngas firing, and 25 ppmvd NOx at 15% O_2 for natural gas firing.

The BACT selection of diluent injection to the NO_x levels described above is strongly supported by recent precedents for similar IGCC projects. Diluent injection was designated as LAER for an IGCC combustion turbine project in Delaware (Motiva/Star Enterprises), as BACT for three new IGCC projects in Wisconsin (We Energies), Kentucky and Ohio (Global Energy) and as BACT in a BACT re-evaluation of an existing IGCC facility in Florida (Tampa Electric).

Implementation of add-on controls such as SCR and SCONOx™ is subject to significant technical feasibility issues with regard to their application to IGCC units, and are not commercially demonstrated for such an application. The PMEC facility has proposed installation of SCR as an ICT, and will accept alternate NO_x emission limits based on this technology target of 3 ppmv NO_x at 15% O_2 for syngas firing, and 5 ppmv NO_x at 15% O_2 for natural gas firing. The demonstration period for these alternate ICT limits should be tied to a schedule for achieving specific emission rate performance and reliability milestones, starting from the initial date of SCR system operation (first day exhaust is treated). If there is evidence after a sufficient test period that the use of Selexol® or equivalent and SCR will not be capable of reliably achieving the ICT limits described above, then some relaxation of these limits will be warranted. Energy Northwest will work closely with EFSEC to establish the ICT timetable and interim target emission rates.

B-1.7.2 SULFUR DIOXIDE AND SULFURIC ACID MIST BACT ANALYSIS

B-1.7.2.1 Identify Control Technologies

Sulfur dioxide emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of syngas in the combustion turbines creates primarily SO_2 and small amounts of sulfite (SO_3) by the oxidation of the fuel sulfur. The SO_3 can react with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled, either by limiting the sulfur content of the fuel (pre-combustion control) or by scrubbing the SO_2 from the exhaust gas (post-combustion control). Potentially available control technologies include:

Pre-Combustion Process Controls

- Chemical Absorption Acid Gas Removal (AGR), e.g., MDEA
- Physical Absorption, e.g., Selexol®, Rectisol®

Post-Combustion Controls

- Flue Gas Desulfurization (FGD)

Acid Gas Removal (AGR)

In the gasification process sulfur in the petroleum coke or coal feedstock converts primarily to hydrogen sulfide (H_2S) and, to a lesser extent, to other sulfur species such as carbonyl sulfide (COS). A COS hydrolysis unit is provided in IGCC plants to achieve a higher level of sulfur removal. In the hydrolysis unit, the COS is converted to H_2S, which is more efficiently removed in an AGR system. Solvent-based acid gas cleanup is commonly used for "gas sweetening" processes in refinery fuel gas or tail gas treatment units, where H_2S in the process gas is removed before use as a fuel or release to the atmosphere. The removed H_2S is recovered either as elemental sulfur in a Sulfur Recovery Unit (e.g., using a Claus process) or converted to H_2SO_4 in a sulfuric acid plant.

Chemical absorption occurs in amine-based systems that use solvents such as methyldiethanolamine (MDEA). Amine solvents chemically bond with the H_2S. The H_2S can be easily liberated with low-level heat in a stripper to regenerate the solvent. This is the technology that has been used in all existing and recently-permitted IGCC facilities, and is considered the baseline BACT level of control for this application.

The operating IGCC facilities at Polk Power Station and Wabash River (SG Solutions) both use amine systems to treat the syngas to total sulfur levels of 100 to 400 ppm. A few IGCC permits were issued between 2001 and 2004 with amine systems designed to treat syngas down to 40 ppm sulfur – however, none of these projects has yet been constructed. While some recent IGCC permit applications (permits pending) have proposed as BACT MDEA systems scrubbing to syngas sulfur levels of 50-75 ppm levels, others (including PMEC) have proposed more aggressive controls such as Selexol®.

Similar or lower levels of sulfur removal are possible using physical absorption AGR systems. The AGR system proposed for the PMEC is an enhanced level of physical absorption employing the Selexol® or equivalent technology that uses mixtures of dimethyl ethers of polyethylene glycol. This process, which will achieve a long-term average of 10 ppmv reduced sulfur in the syngas, is an integral part of the ICT options proposed for inclusion in the PMEC permit. As described in the previous turbine NO_x BACT section, low sulfur levels in the syngas fuel are essential to the viability of SCR for control of reduced turbine NO_x emissions.

Another comparable AGR technology, Rectisol®, utilizes refrigerated methanol as the physical solvent. In these types of AGR processes the H_2S is dissolved under pressure into the solvent. Dissolved acid gases are removed by depressurization to regenerate the solvent for reuse. Physical absorption methods have been used for many years to purify gas streams in the chemical processing and natural gas industries. For example, Selexol® was used with high-sulfur coals in the Cool Water IGCC Project, which was a demonstration facility operated from 1984 – 1988.

The various physical and chemical absorption systems for acid gas removal can be operated at varying levels of efficiency, with capital and operating costs increasing for increasing sulfur removal. In general, the Selexol® and Rectisol® systems can achieve lower sulfur levels than conventional MDEA absorption, or other amine-based chemical absorption systems. There are also operating conditions where the removal efficiencies overlap. For example, MDEA systems are generally the most cost-effective for lower levels of sulfur removal, but the costs increase significantly if deeper sulfur removal is required. In contrast, a Selexol® system would have higher initial capital costs, but would be able to achieve deeper removal levels at a lower incremental cost.

Flue Gas Desulfurization

Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

FGD systems are commonly employed in conventional PC plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95% sulfur removal.

B-1.7.2.2 Evaluate Technical Feasibility

Both chemical and physical absorption methods for AGR are considered feasible for an IGCC, and can achieve control of the sulfur in syngas up to 99% or better. Both of these systems are further considered in this analysis.

FGD cannot provide as high a level of control as the pre-combustion AGR systems. In addition, FGD has the environmental drawbacks of substantial water usage and the need to dispose of a solid byproduct (the scrubber sludge). Given these disadvantages, even though FGD is not technically infeasible, it is not considered to be a reasonable technical option for IGCC. The sulfur would be removed more efficiently and economically from syngas prior to combustion in the combustion turbines; therefore FGD will not be considered further in this BACT analysis.

B-1.7.2.3 Rank Control Technologies

The technically feasible technologies for controlling syngas sulfur levels, and thus turbine SO_x emissions, are summarized in Table B-1-5 in descending order of control efficiency. Emissions in pounds per million Btu of coal feedstock and annual emissions for two combustion turbines are also shown along with uncontrolled and NSPS emissions limits for comparison.

TABLE B-1-5
RANKING OF SO_2 BACT EMISSION LIMIT OPTIONS

Control Technology Option	Sulfur in Syngas (ppm)	Control Efficiency	SO2 Emission Limit (lb/MMBtu input as coal) 2	Annual SO2 Emissions – Per Turbine (tons/yr) 3	Emissions Reduction (tons/yr)
AGR to 1 ppm (requires Rectisol)	1	99.99%	0.0005	6.5	318.5
AGR to 10 ppm (using Selexol®)	10	99.90 %	0.0050	65	260
AGR to 50 ppm[1] BACT Baseline Control Option	50	99.50%	0.0251	325	325
AGR to 100 ppm[1]	100	99.25%	0.05	650	-

1 -- Treatment of syngas to 50-100 ppm sulfur levels could be achieved with either an MDEA or Selexol® AGR system.
2 – Each emission limit must be combined with an averaging time that is suitable for the technology, and the reasonable expectations of process variability. For AGR, the presumed rolling average time is 30 days.
3 – Annual emissions for purposes of this BACT comparison does not include gasifier or turbine startup emissions.

B-1.7.2.4 Evaluate Technical Feasibility

Depending on the feedstock used, the syngas initially produced could contain more than 10,000 ppm sulfur for the worst-case feedstock, primarily in the form of H_2S. In an IGCC process, chemical absorption processes such as AGR with MDEA have been used for existing and permitted IGCC facilities. The normal level of removal for this type of technology is therefore considered the baseline level of control for purposes of this BACT assessment.

The most effective SO_2 control system that is considered to be technically feasible is the physical absorption AGR system using Rectisol to 1 ppm sulfur in syngas, as shown in the table above. The next levels of control can be achieved with either a Selexol®/equivalent or an MDEA system. Table B-1-6 shows incremental emissions reduction that can be achieved and the associated costs for a range of sulfur removal efficiencies compared to the IGCC baseline syngas sulfur level of 50 ppm.

B-17.2.5 Environmental and Economic Impacts

Table B-1-6 shows the average and incremental costs for varying levels of sulfur removal at the proposed PMEC. For this analysis, removal to 50 ppm was chosen as the base, or minimum BACT level of control for IGCC syngas. Significant sulfur removal (versus "uncontrolled" levels) is required at an IGCC facility. It would not be feasible to combust uncontrolled "raw" syngas in the combustion turbines.

TABLE B-1-6
ANNUALIZED COST EVALUATION FOR CANDIDATE BACT SO_2 CONTROL TECHNOLOGIES

Control Technology	Capital Investment (10^6 \$)	Annual Operating Costs (10^6 \$/yr)	Total Annualized Costs (10^6 \$/yr)	Baseline Emissions or Reduction (tons/yr)[1]	Cost Effectiveness (\$/ton)
AGR to 1 ppm (Rectisol)	39.961	4.106	8.494	319	$26,662
AGR to 10 ppm (Selexol®)	20.980	2.891	5.195	260	$19,975
AGR to 50 ppm[1] **BACT Baseline Control Option**	-	-	-	**325**	-

1 - Treatment of syngas to 50-100 ppm sulfur levels could be achieved with either an MDEA or Selexol® AGR system. Tons of SO_2 reduced are based on comparison with MDEA system at 50 ppm level.
2 – Each emission limit must be combined with an averaging time that is suitable for the technology, and the reasonable expectations of process variability. For AGR, the presumed rolling average time is 30 days.
3 – Annual emissions for purposes of this BACT comparison does not include gasifier or turbine startup emissions.
Note: *Basis for these cost estimates is provided in Attachment B-1-2.*

Although all the AGR systems require chemical handling and will generate a sour water stream, there are no unique collateral environmental issues that would preclude any of the systems from consideration as BACT. Both physical and chemical absorption-based AGR systems involve chemical processing systems that use solvents to remove H_2S from the syngas. The solvent in each system can be regenerated and reused. Acid gases removed from the syngas in each type of process will be processed to generate elemental sulfur in a separate sulfur recovery system. Each acid gas removal system will generate a sour water stream that must be processed prior to discharge. The potential for fugitive emissions of reduced sulfur compounds from these processes increases as the processes become more complex. Consequently, the capital costs of the AGR systems must assume that fittings and valves are specified to meet low-emission criteria.

B-1.7.2.6 Select Control Technology

The applicant proposes that BACT for control of SO_2 combustion turbine emissions from the IGCC facility (and concurrently for acid mist emissions) be defined as treatment of the syngas by acid gas removal to achieve a syngas sulfur concentration of 50 ppm.

However, the applicant intends to install the Selexol® or equivalent physical absorption system, which will remove more than 99% of the sulfur contained in the syngas used to fuel the combustion turbines and/or achieve a long-term average syngas reduced sulfur species content equal to or less than 10 ppmvd. Syngas at this reduced level of sulfur will result in annual average turbine SO_2 emissions of 0.0053 lb/MMBtu, based on gasifier heat input. Typical BACT determinations for prior IGCC projects utilizing physical absorption processes have operated with approximately 50 ppmv of sulfur remaining in the undiluted, unsaturated syngas (i.e., upstream of final conditioning). The enhanced level of sulfur treatment proposed by PMEC is a necessary prerequisite for effective SCR operation, and is therefore an integral component of the ICT proposed for the combustion turbines.

Use of Selexol® or equivalent to a 10 ppm sulfur level compared to chemical absorption at a 50 ppm level has an incremental cost effectiveness of almost $20,000 per ton of avoided SO_x emissions. Treatment to an even lower level of sulfur, while technically feasible, would be prohibitively more expensive. Achieving a level of 1 ppm sulfur in the syngas fuel using Rectisol® is estimated to require approximately $19 million additional capital investment for the AGR system and $1.2 million dollars per year of additional operating costs. Based on the total emission reduction from the MDEA baseline option, the cost-effectiveness to achieve this most-stringent level of emission equates to approximately $26,660 per ton of SO_2 controlled. Consequently, the annualized cost for an additional reduction of 58 tons per year is economically prohibitive. Therefore, PMEC proposes to implement a Selexol® system or equivalent to remove sulfur (H_2S + COS) down to 10 ppmvd (30-day rolling average) in the undiluted, unsaturated syngas prior to combustion in the combustion turbines.

The proposed turbine SO_2 emission rate of 0.0053 lb/MMBtu (as coal input to the gasifiers) compares very favorably with the new NSPS for Electric Utility Steam Generators (including IGCC) in 40 CFR 60 Subpart Da, which sets a standard of 2.0 lb/MWh, or approximately 0.2 lb/MMBtu. The desulfurization of the combusted fuel that is achieved with IGCC, and the resultant reduction in SO_2 emissions is one of the major environmental advantages of IGCC technology compared with other coal-based power generation systems.

B-1.7.3 VOLATILE ORGANIC COMPOUND BACT ANALYSIS

VOCs are a product of incomplete combustion of the organic syngas fuel. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. The primary technologies identified for reducing VOC emissions from the IGCC combustion turbines are oxidation catalysts and good combustion practices (GCP). A survey of the RBLC database indicated that good combustion control and burning clean gas fuel are the VOC control technologies primarily determined to be BACT. An inherent advantage of IGCC technology is the fact that the combustion turbines use syngas, a fuel which contains a very low organic content and, when burned, yields very low levels of uncombusted VOC emissions.

B-1.7.3.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the IGCC combustion turbines for control of VOC emissions:

Combustion Process Controls

- IGCC technology (use of low VOC syngas)
- Good Combustion Practices (GCP)

Post Combustion Controls

- Oxidation Catalysts

B-1.7.3.2 Evaluate Technical Feasibility

Low-VOC Syngas Fuel

Combustion of any hydrocarbon material can produce trace levels of uncombusted VOCs. However, combustion of fuels with very low hydrocarbon content can obviously further lower these VOC emissions. The very nature of the IGCC process leads to unusually low levels of any organic emissions from syngas combustion.

The gasification process involves feeding a slurry of carbon-containing materials into a heated and pressurized chamber (the gasifier) along with a controlled and limited amount of oxygen. At the extremely high operating temperature and pressure created by conditions in the gasifier, chemical bonds are broken by oxidation and steam reforming at temperatures sufficiently high to promote very rapid reactions. The various constituents in the feedstock are largely broken down into their fundamental elements in the gasifier, and are reformed in the syngas primarily in the form of diatomic hydrogen (H_2) and CO gas.

Good Combustion Practices (GCP)

GCPs applied to the proposed sources can achieve VOC emission levels below 3 ppmvd (at 15 percent O_2) based on data provided by Fluor. GCPs include operational and design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. This is the technology used as BACT for all other recent IGCC permits.

Oxidation Catalyst

The option that has greatest uncertainty with respect to cost, long-term performance and reliability for application to IGCC turbines is the use of oxidation catalysts. Catalytic oxidation is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed at the appropriate temperature point in the HRSG. The catalyst promotes the oxidation of VOC. The catalyst beds that reduce CO can also be effective in reducing VOC emissions. Such systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing upwards of 90% control for CO.

It is also worth noting that a typical additional incentive to using an oxidation catalyst, when feasible, is the incidental control of organic hazardous air pollutants (HAPs). For example, uncontrolled formaldehyde (CHOH) emissions can be fairly significant from conventional combustion of natural gas. However, since syngas contains primarily elemental hydrogen (H_2) and CO, uncontrolled turbine emissions of formaldehyde and other organic HAP emissions, are significantly less. The reaction path to create formaldehyde is not present for hydrogen and CO fuel constituents. For this reason, oxidation catalyst, even if feasible, would provide less benefit for a syngas-fired combustion turbine versus a natural gas-fired combustion turbine.

Oxidation catalysts are anticipated to experience performance problems due to the presence of low-levels of sulfur and trace metals in the syngas combustion exhaust, as further described in the CO BACT evaluation. The presence of sulfur compounds in the combustion turbine exhaust gases, even with the proposed BACT limit of 10 ppmv in the syngas, will cause poisoning of the metal-catalyst active sites in the catalyst pores. This will result in a more rapid decay in catalytic oxidizer module performance, and increased cost for more frequent catalyst replacement. Further, oxidation catalysts have seldom been applied, and are not viewed as commercially proven on coal-based combustion systems. For all these reasons, catalytic oxidation is not considered a practical or feasible technology for VOC removal for this IGCC application.

B-1.7.2.3 Select Control Technology

The recommended control of VOC emissions from each of the proposed combustion turbines is use of the low VOC fuel and GCPs at the IGCC combustion turbine. These practices will meet a VOC emission limit of 0.003 lb/MMBtu input to the gasifier, or 10 lb/hr/combustion turbine while operating under steady state conditions. This equates to approximately 2.4 ppmv at 15% O_2 in the stack gases. During start up cycles, the proposed BACT limitation on VOC emission is 263 lb/hr, which represents the worst case emission rate during syngas system start up.

B-1.7.4 CARBON MONOXIDE BACT ANALYSIS

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, can also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control (by diluent injection or dry lean pre-mix) may result in higher levels of CO emissions. Thus, a compromise must be established, whereby the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Possible post-combustion control involves the use of catalytic oxidation, while front-end control involves controlling the combustion process to suppress CO formation.

B-1.7.4.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the PMEC combustion turbines for control of CO emissions:

Combustion Process Controls

- Good Combustion Practices (GCPs)

Post Combustion Controls

- SCONOx™
- Oxidation Catalyst

B-1.7.4.2 Evaluate Technical Feasibility

Each identified technology was evaluated in terms of its technical feasibility for application to IGCC combustion turbines burning syngas. In general, post-combustion controls either had substantial feasibility issues, or did not offer a level of control that was practically better than GCP.

SCONOx™

The $SCONO_x$™ system was described in the BACT analysis for control of turbine NO_x emissions. It is commercially available for small-frame combustion turbines for controlling CO and can reduce emissions by up to 95 percent. However, it is not commercially available for large frame combustion turbines (like those to be used for PMEC) as discussed in the NO_x BACT discussion. Therefore, SCONOx™ is considered to be technically infeasible for PMEC.

Oxidation Catalysts

Catalytic oxidation is a post-combustion technology, which does not rely on the introduction of additional chemical reagents to promote the desired reactions. They have been permitted as required CO control equipment for a fairly large number of natural gas combustion turbine applications. The oxidation of CO to CO_2 utilizes excess air present in the combustion turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The introduction of a catalyst bed in the combustion turbine exhaust stream will create a pressure drop, resulting in back pressure to the combustion turbine. This has the effect of reducing the efficiency of the combustion turbine and the power generating capabilities.

As previously mentioned, a common incentive to use a CO oxidation catalyst, if feasible, would be the incidental control of VOC and organic HAPs that would be realized in conjunction with reduced CO emissions. However, as discussed in the VOC BACT section, such benefits are less significant for gas turbines using syngas fuel, which has a very low VOC content, than for units burning natural gas.

A CO catalyst oxidizes CO to CO_2 and VOC and unburned hydrocarbons to CO_2 and H_2O, but also can promote other oxidation reactions such as NH_3 to NO_x and SO_2 to SO_3. Consequently, the presence of a CO catalyst can cause emissions of other pollutants to increase, and therefore its design needs to be carefully considered.

CO catalyst typically operate at temperatures between 750 to 1100°F (400 to 600°C), and typically the catalyst is more effective at promoting the oxidation reactions as the operating temperature increases. Typical CO to CO_2 conversion efficiencies from a CO oxidation catalyst are 80 to 90%, and typical VOC conversion efficiencies are 40 to 50%.[[6]]

At 750°F (400°C), a CO oxidation catalyst will also promote conversion of up to 35% of the SO_2 to SO_3, according to the Electric Power Research Institute (EPRI). At 1000 to 1100°F (538 to 600°C), the catalyst will promote an even higher rate of conversion of SO_2 to SO_3. Significant concentrations of SO_3 can promote the formation of visible sulfuric acid mist (also known as a "blue plume") when the exhaust gas cools below the sulfuric acid dewpoint.

If a high temperature (>1000°F or 538°C) CO catalyst is used, in order to avoid producing excessive SO_3, the sulfur content of the syngas must be low enough to yield no more than 2 ppmv SOx in the combustion turbine exhaust in order to avoid the blue plume. However, even if a lower temperature CO catalyst is used, the resulting SO_3 concentration would cause unacceptably high rates of ammonium bisulfide formation if an SCR is also present in the HRSG. Therefore, a CO catalyst is not recommended by EPRI for use in IGCC systems which incorporate an SCR. [[7]]

By placing the catalyst at the correct position within the HRSG, the temperature can fall within the range appropriate for CO catalytic oxidation. However, the same catalyst fouling issues mentioned in regard to SCR catalysts for NO_x control will be of concern with CO oxidation catalysts. Compounds in the syngas exhaust, such as sulfur, can cause plugging or deactivation of the CO catalyst, greatly shortening its service life and increasing periodic replacement costs. Even the relatively low concentrations of heavy metals predicted for the IGCC combustion turbine exhaust may adversely affect the performance and longevity of a catalytic oxidation system. Therefore, oxidation catalysts are considered to be technically infeasible for this project.

The Florida Department of Environmental Protection recently established a precedent for the use of an oxidation catalyst as BACT for CO at an IGCC facility in Florida. Specifically, Florida published its Technical Evaluation and Preliminary Determination document on June 16, 2006 for the Curtis H. Stanton Energy Center Unit B proposed by OUC & Southern Power Company – Orlando Gasification LLC. This document includes the Department's BACT analysis for the Stanton project, which found that use of a CO oxidation catalyst is cost effective for that application. However that finding pertained to an unsteablished demonstration IGCC technology that cannot be considered in PMEC (the KBR "Transport Gasfier" in a subbituminous coal-fueled IGCC process) and did not refute the concerns expressed above regarding the serious technical feasibility issues with regard to power plant reliability.

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[6] "Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production", California Air Resources Board, http://www.arb.ca.gov/energy/powerpl/appcfin.pdf
[7] ERPI CoalFleet IGCC Permitting Guidelines Manual, Electric Power Research Institute, March 2006.

The Department obtained costs from a CO catalyst vendor, but apparently no written guarantee that the control system would perform at the level to meet the levels of 4.1 ppmvd CO and 2.4 ppmvd VOC, which were included in the facility's permit. The agency proposes that the oxidation catalyst be installed during the second year of the IGCC unit's operation to allow time for stabilization of the gasifier system and implement additional changes, such as better syngas cleaning, if necessary. This use of oxidation catalyst is not an instance of the oxidation catalyst technology having been proven in practice. In addition, as a demonstration project selected for funding assistance by the Department of Energy, the Stanton Project will receive $235 million of the total cost of $557 million from DOE, an advantage not shared by PMEC.

Good Combustion Practices

Good combustion practices (GCPs) include operational and combustor design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. Such control practices applied to the proposed PMEC combustion turbines can achieve CO emission levels of 15 ppm during steady state, full load operation. At lower combustion turbine loads (50-70%), the combustion efficiency drops off notably, and CO emissions would be higher. However, the PMEC combustion turbines are expected to operate for only 50 hours or less per year in startup mode, and this profile (15 ppmvd at 15% O_2) was used as the basis of the BACT analysis.

GCPs are a technically feasible method of controlling CO emissions from the proposed IGCC combustion turbines.

B-1.7.4.3 Rank Control Technologies

The only CO control technology found to be technically feasible for the PMEC combustion turbines burning syngas fuel is presented in Table B-1-7

TABLE B-1-7
RANKING OF FEASIBLE CO CONTROL TECHNOLOGIES FOR GAS TURBINES

Control Technology	Removal Efficiency Range (%)	Controlled Emission Level
GCPs	Not Applicable (baseline)	15 ppmv @ 15% O_2 2,740 lb/hr (startup)

B-1.7.4.4 Select Control Technologies

GCP is considered the baseline and only feasible and commercially demonstrated CO control technology for IGCC combustion turbines. The conditions that led to the recent finding in favor of CO catalyst technology a BACT for Curtis H. Stanton Energy Center Unit B project do not exist for the PMEC. Additionally, GCP has been selected as BACT for all other recent IGCC permits. PMEC proposes that the CO BACT-based limit should be 15 ppmvd @ 15 percent O_2 on a 3-hour average during non-startup operation, using Good Combustion Practices (GCPs). Similarly, for the maximum CO emission limit during turbine startup with GCP is proposed to be 2,740 lb/hr, with an assumed level of 50 hours per year of startup operation for each turbine for purposes of estimating annual emissions.

B-1.7.5 PARTICULATE MATTER BACT ANALYSIS

Particulate matter emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the combustion turbine inlet air filters and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate matter emissions. Clean gaseous fuel, such as syngas, will also be low emitting. In the PMEC process, as in other IGCC systems, the hot syngas exiting the gasifier is cooled and sent to a water scrubbing system for particulate matter removal prior to other gas treatment processes such as AGR.

The EPA has indicated that particulate matter control devices are not typically installed on combustion turbines and that the cost of installing a particulate matter control device is prohibitive (EPA, September 1977). When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the recently revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for particulate matter control of stationary gas turbines have not been proposed or promulgated at a federal level.

Post combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses is considered technically infeasible, and does not represent feasible control technology.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low ash fuel, such as natural gas or syngas. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas or syngas) is the predominant control method listed.

The use of clean syngas fuel and good combustion control is proposed as BACT for PM/PM_{10} control in the proposed PMEC combustion turbines. These operational controls will limit filterable plus condensable PM/PM_{10} emissions to 24 lb/hr, based on 0.01 lb/MMBtu input to the gasifier when operating on syngas.

PMEC is proposing to build enclosed solid fuel storage to improve storage management and minimize particulate emissions.

B-1.7.6 MERCURY BACT ANALYSIS

Since mercury occurs naturally in PBR coals, the PMEC syngas cleanup processes include a system to control mercury that may remain in the syngas. Downstream of the AGR system, the syngas passes through fixed beds of activated carbon that are specially impregnated to remove mercury. Multiple beds in series are used to obtain optimized adsorption. The lower temperature and lower moisture content of the syngas after the Selexol® or equivalent step allows the carbon beds to operate at higher efficiencies. The activated carbon capacity for mercury ranges up to 20% by weight of the carbon. The mercury removal system will remove enough mercury from the syngas so that the mercury content of the syngas fuel is no more than 10% of the mercury contained in the solid IGCC feed stock. After mercury removal, the product syngas is moisturized, heated, and diluted with nitrogen for control of nitrogen oxides (NO_x) before being used as fuel for power generation in the CTGs.

PMEC's mercury emission calculations assume that the mercury remaining in the syngas after carbon adsorption is emitted in the exhaust of the combustion turbines and other combustion units,. On this basis, the mercury emissions for both combustion turbines are estimated to be 58 lbs per year. Much smaller amounts would be released from the flare, tank vent oxidizer, auxiliary boiler and cooling tower. However, these smaller sources account for less than 2 lbs per year.

B-1.7.6.1 Identify Control Options

Among IGCC facilities that have achieved operating status, only one was found to have permitted emission limits that directly address mercury emissions. Based on engineering development in support of later IGCC permit applications, the use of carbon adsorption is the only technology that has been proposed as a technically feasible method of control specifically for mercury. The following list summarizes the nature of mercury emission limits or proposed control technologies for several IGCC facilities:

- SG Solutions, Wabash River Generating Station, Indiana (Operating)
  - No mercury limits in NSR permit.
- Tampa Electric Company, Polk Power Station, Florida (Operating)
  - Maximum allowable mercury limits in NSR permit for "demonstration period" of 0.025 lb/hr and 0.11 tons per year, and for "post-demonstration" period of 0.0034 lb/hr and 0.017 tons per year.
  - Testing requirement to prove compliance with limits
- Global Energy Inc., Kentucky Pioneer Energy, LLC, Kentucky (Permitted)
  - Stack emission limits of 0.080 milligrams per dry standard cubic foot
  - Testing requirement to prove initial compliance with limit
- Mesaba Energy Project, Minnesota – 1,200 MW(Proposed)
  - Carbon adsorption proposed as control technology
  - Proposed mercury emissions in NSR application based on not less than 90% removal of mercury present in the fuel feedstock, which corresponds to maximum annual emissions of 54 lbs/year[8].
  - Project will comply with NSPS for Coal-Fired Electric Steam Generating Units (40 CFR 60, Subpart Da(b)) standard for IGCC units of 0.000020 lb/MWh (0.0025 ng/J) based on gross electric output.

[8] Mercury emissions presented in the Mesaba air permit application were estimated based on an emission factor of 0.5 lb/10^{12} Btu of feedstock for PRB coal. PMEC has conservatively estimated its mercury emissions using an emission factor of 1.2 lb/10^{12} Btu, which is at the high end of measured Hg levels for PRB coal. This explains the comparable annual emissions estimates for the two facilities, despite the fact that the Mesaba calculations pertain to a 1200 MW IGCC facility while the PMEC will generate only 600 MW.

- Curtis H. Stanton Energy Center, Orlando, Florida – 285 MW (Proposed)
  - Carbon adsorption proposed as control technology
  - Annual emissions are less than BACT significance level for mercury, which is 200 lb/yr
  - Proposed mercury emissions in NSR application were based on average of 90% removal of mercury in present in the fuel feedstock.
  - Agency-proposed permit limit is 0.000010 lb/MWh, which is half of the limit in NSPS (40 CFR 60, Subpart Da(b)) for IGCC units, and corresponds to approximately 22 lb/yr.

B-1.7.6.2 Evaluate Control Options

Operating experience with IGCC processes is relatively limited, so the long-term reliability and performance of specific emission controls for mercury is not well-demonstrated at the commercial scale. At very least, the volume of activated carbon needed for high efficiency adsorption of mercury must be adjusted to account for the potential loss of capacity due to adsorption of sulfur compounds, or other species in the syngas. There is no reported experience to judge the required frequency of replacement for activated carbon in syngas cleanup service.

Consideration of the physical process of adsorption in a carbon bed suggests that higher removal levels would not be achieved by simply increasing the volume of carbon. When a fresh or regenerated bed of carbon is brought into service, the material nearest the gas entrance will capture the contaminant until its surface is essentially "saturated", or it approaches its equilibrium capacity for that prevailing inlet concentration. As unabsorbed molecules travel further into the bed, additional carbon surface becomes saturated. In this manner, an "adsorbing zone" travels through the bed in the direction of gas travel. The exit gas concentration of the contaminant is established by gas-solid equilibrium factors (i.e., surface activity, temperature, pressure, and concentration), rather than mass transfer limits. Enlarging the carbon bed will extend the time before "breakthrough", the point when the entire bed is saturated, but will not appreciably reduce the exit concentration of the contaminant.

In the mercury material balance used to estimate emissions, the primary process specification is that sufficient adsorption capacity will be provided to capture 90% of the mercury in the fuel feedstock. Conservatively, it has been assumed in this application that all of the feedstock mercury will be converted to a gaseous mercury species in the gasifier. In actuality, the feedstock mercury will partition between the gasifier slag and the product gas, in a proportion that is variable and not accurately calculable without measurements for a specific fuel blend.

B-1.7.6.3 Proposed BACT Limit

Given the uncertainty inherent in the mercury balance calculations, and the lack of commercial demonstration of the single feasible control technology, there is no justification to identify BACT control options that are more stringent than the applicable NSPS. For these sources, the BACT "floor" is the recently-revised and relatively stringent limit of a 12-month rolling average of 0.000020 lb/MWh (0.0025 ng/J) based on gross electric output (40 CFR 60.45 Da(b)). With the exception of the most recent proposed permit for the IGCC in Orlando, Florida, all of the prior permits for IGCC have contained limits equivalent to or less stringent than the NSPS. It remains to be seen whether the Florida permit limit of 0.00001 lb/MWh can be achieved, given the chemical equilibrium limitations on carbon adsorption of mercury.

For mercury emissions from the IGCC combustion turbines, the carbon adsorption design will deliver at least 90% removal of the mercury contained in the feedstock fuel. For PRB coal, this results in a maximum emission rate of 0.0033 lb/hr per turbine (0.000011 lb/MWh) Based on information recently presented in the Mesaba IGCC New Source Review permit application, the mercury content in PRB coal is higher than in petroleum coke. Thus, the emissions estimate based on this coal mercury content represent a worst-case for the PMEC facility. This limit is proposed as the BACT limit for the PMEC project. The estimated maximum annual emission rate of 29 pounds of mercury per year from each of the PMEC combustion turbines is compliant with the NSPS standard.

B-1.8 BACT DETERMINATION - PRECEDENTS FOR SOLID FUEL HANDLING FACILITIES

Various types of industrial facilities include solid fossil fuel handling operations. To review recent BACT precedents for these operations, the RBLC database was surveyed for utility plants and other coal handling operations. These precedents are summarized in Table B-1-8. The control technologies and BACT limits identified in these recent precedents offer guidance for evaluation of BACT options for the PMEC solid fuel unloading, handling and storage operations. The control technologies that may practically establish a BACT emission limit for particulate emission sources in this case are fabric filter baghouses, ESPs, wet scrubbers, and mechanical cyclones. The following general analysis of particulate control technology options feeds into the discussions on BACT for specific IGCC processes involving bulk fuel handling in Sections B-1.9, B-1.10 and B-1.11.

Fabric Filter Baghouse – A fabric filter baghouse collects particulate matter by passing the exhaust gas stream through a series of filters that are constructed of a porous fabric. As the gas passes through the fabric, the dust particles gather on the surface to form a "cake", which further assists in collecting particulate matter. The method with which the cake is removed is critical to the overall success of the control device. If too much of the cake is removed, there will be additional particulate matter emissions, as the baghouse works to reform the cake. If not enough of the cake is removed, the pressure drop across the baghouse will continue to increase, putting a strain on the system itself.

Two common methods for removing the particulate matter dust cake include reversing the air flow periodically (reverse-air baghouse) or using a pulsed jet of compressed air periodically (pulse-jet baghouse). The selection of the fabric material used is also critical to the overall performance of the baghouse. The material must be able to withstand the maximum temperature and flow-rate of the exhaust gas stream, as well as be chemically compatible with both the exhaust gas and the dust that is being collected.

Electrostatic Precipitator – An ESP uses electrical forces to collect particulate matter from the exhaust gas stream. The particles are first passed through a corona where they acquire an electrical charge before being collected on plates, which are oppositely charged. The particulate matter is knocked loose from the plates in such a manner that it is not re-entrained in the exhaust gas stream, and is then transferred to a hopper for disposal. However, the low moisture and high solids loading that characterize the exhaust gas make an ESP less efficient than a fabric filter baghouse.

Wet Scrubber – Wet scrubbers reduce emissions by entraining particulate matter in the exhaust gas stream in water droplets. These droplets are then separated from the remaining gas stream. There are three methods in which the particulate matter is entrained in a water droplet:

- Impaction – the particle collides directly with the water droplet;
- Interception – the particle is captured as it moves close to the water droplet; and
- Diffusion – the particle is circulated through the exhaust gas until it can be captured by the water droplet.

In order to be successful at removing particulate matter, the scrubber must be able to create and effectively control water droplet dispersion.

Mechanical Cyclones – A mechanical cyclone can be used to collect particulate matter from exhaust gases by working in a manner similar to a centrifuge. As the exhaust gas flows through the cyclone, the particulate matter is forced to the sides of the cyclone where it is trapped along the wall. Gravity then pulls the particulate matter down the cyclone where it is collected in a hopper.

In addition to a control device, it is important to note that in order for such "end-of-pipe" devices to be effective, the particulate matter emissions need to be captured. Additional measures are usually included with the control device to constitute a complete capture and control system. These control options are discussed in more detail below.

Full and Partial Enclosures – Particulate matter emissions can be effectively limited by covering equipment or emission points with either full or partial enclosures. The types of

TABLE B-1-8
REVIEW OF RECENT BACT DETERMINATIONS FOR SOLID FEED STOCK OPERATIONS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
CO-0055	02-03-06	Powers County, CO	Lamar Utilities Board DBA Lamar Light & Power	Coal Handling and Preparation	150 ton/hr	PM_{10} – 0.02 lb/ton	High Efficiency Fabric Filter Baghouses (99.50% Efficiency)	BACT-PSD
AR-0082	08-30-05	Independence County, AR	Arkansas Lime Company	Coal/Coke Bin Vent	NA	PM_{10} – 0.0150 gr/dscf 5% opacity	Dust Collector (99% efficiency)	BACT-PSD
CO-0057	07-05-05	Pueblo County, CO	Public Service Company of Colorado	Coal Handling and Storage	NA	PM – 0.01 gr/dscf PM_{10} – 0.01 gr/dscf	Controls include use of water sprays, lowering well, dust suppressants, enclosures and baghouses where feasible.	BACT-PSD
MN-0061	06-26-05	St. Louis, MN	Mesabi Nugget LLC	Coal Pulverizer	36 MMBtu/hr	CO – 3 lb/hr NO_X – 1.8 lb/hr PM – 0.01 gr/dscf PM_{10} – 0.0150 gr/dscf VOC – 0.19 lb/hr' 10% opacity	Fabric Filter	BACT-PSD
ND-0021	06-03-05	Bowman County, ND	Montana Dakota Utilities / Westmoreland Power	Coal Handling	400 ton/hr	PM – 0.0050 gr/dscf 5% opacity	Baghouses (99.9% Efficiency)	BACT-PSD
IN-0119	05-31-05	Dekalb County, IN	Auburn Nugget	Coal Car Unloading	165 ton/hr	PM – 0.0052 gr/dscf 3% opacity	Baghouse	BACT-PSD
NV-0036	05-05-05	Eureka County, NV	Newmont Nevada Energy Investment LLC	Coal Handling Operations	NA	PM_{10} – 0.01 gr/dscf	Baghouse	BACT-PSD
VA-0292	11-02-04	Buchanan County, VA	Island Creek Coal	Coal Handling and Transfer Operations	3.5 MMton/yr	PM – 16.95 ton/yr PM_{10} – 3.35 ton/yr	Wet Suppression	BACT-PSD
ND-0020	08-04-04	Stark County, ND	Red Trail Energy LLC	Coal Handling	27 ton/hr	PM_{10} – 0.0040 gr/dscf 0% opacity	Baghouse (99.8% Efficiency)	BACT-PSD
SC-0104	02-05-04	Berkeley County, SC	Santee Cooper	Coal Handling	26.28 MMton/yr	PM – 1.4 lb/hr	Baghouse (99.50% Efficiency)	Other Case-by-Case

B-1.9 BACT ANALYSIS FOR RAILCAR UNLOADING AND TRANSFER POINTS

B-1.9.1 PROCESS DESCRIPTION

Energy Northwest expects that fuel selection throughout the lifetime of the PMEC will respond to market conditions and economic considerations. The primary feed stocks will be petroleum coke and coal; natural gas will be the backup fuel. Either petroleum coke or coal feedstocks may be received by rail in dedicated unit trains. However, most petroleum coke is expected to be delivered by barge, and emission control options for the PMEC barge unloading facilities are assessed in Section B-1.10. The following BACT analysis for the rail car unloading facility is based on the solid fuel selection with the highest pollutant emission rates among the anticipated range of fuels.

The proposed unloading building will house supporting facilities for railcar unloading operations and facilitates control of dust emissions, noise abatement, and visual shielding. The railcar coal receiving system will incorporate the use of high-capacity aluminum-steel railcar bottoms dumping to an under-rail pit-hopper system. During unloading of a unit train, the railcars will move at a slow speed (approximately 0.3 mph) through the unloading building. The end doors of the building will be covered with plastic slat covers to reduce transport of emissions to the outside air. The load will be dumped from the bottom of each car into a dump hopper under the track. Multiple collecting conveyors will move the dumped fuel from the hopper to an inclined take-away conveyor that moves the solid fuel from the building to the storage domes.
Nominal design capacity for the railcar unloading facility is 4,300 tons of coal per hour, which forms the basis for the emission estimates used in this BACT analysis. Significant emissions from the railcar unloading facility consist only of particulate matter (PM) and particulates less than 10 microns diameter (PM_{10}). Two separate emission units associated with this facility are included in this BACT analysis:

- Railcar unloading pit-hopper; and
- Conveyor and transfer point.

The proposed BACT for both emission points is enclosure in the unloading building, with the entire building maintained at negative pressure for effective capture of generated dust. The under-track conveyor and transfer point will be enclosed. The exhaust air stream from the unloading building will be treated by a high-efficiency fabric-filter baghouse before being vented to atmosphere.

B-1.9.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

Based on current practices for solid material handling systems, several types of commercially available control technologies can be identified for the railcar fuel unloading process at the proposed PMEC facility. An RBLC Database survey indicates that commercially available controls include:

- Unloading building with restricted end door openings and operated at negative pressure with vent stream routed to high-efficiency fabric filter;

- Enclosed batch drop and transfer points with high-efficiency fabric filter;
- Transfer point and batch drop point water sprays,
- Transfer point enclosures only

Based on review of BACT precedents, the emission control option of enclosures with baghouse filters for railcar unloading, handling and storage of petroleum coke and coal had control efficiencies that varied from 99.0% to 99.9%. In addition, water sprays and enclosures are also considered to be available control options for PM_{10} emissions. The ranges of coal handling emission limits for recently permitted sources are as follows:

- PM = 0.0050 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- PM10 = 0.0040 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- Opacity = 0% to 10%

B-1.9.3 INFEASIBLE CONTROL MEASURES

None of the identified emission control options for this source would be viewed as technically infeasible.

B-1.9.4 RANKING OF AVAILABLE CONTROL MEASURES

In approximate order of decreasing stringency these control technology options are:

- Complete enclosure for railcar unloading building and below-grade conveyor and building vented through high-efficiency fabric filter units;
- Railcar unloading pit-hopper enclosure and transfer point enclosures with water or suppressant sprays;
- Enclosed below-grade pit and conveyor only
- Water suppression on railcar unloading bin-hopper and transfer point

B-1.9.5 PROPOSED BACT LIMITS AND CONTROL OPTION

PMEC proposes to adopt the most stringent control option among those identified for this type of particulate emission source. As noted in the discussion of the top-down BACT procedure in the beginning of Section B-1.2, an evaluation of any potential environmental and energy impacts resulting from the implementation of the selected control option must be provided, even when the top-ranked control option is chosen. . The only potential impact associated with a fabric filter baghouse includes an environmental impact associated with the disposal of existing bags when they are replaced with new bags. This is a relatively minor potential environmental impact, such that use of a fabric filter baghouse is reasonably considered to be the top-ranked control option. PMEC will adopt a fabric filter performance specification of 99% particulate removal from the airstreams sent to the baghouse. In combination with an estimated particulate collection efficiency of 80% for the entire railroad unloading system, this results in 89.2% removal of all particulate emissions associated with this process.

B-1.10 BACT ANALYSIS FOR SHIP/BARGE UNLOADING FACILITY AND TRANSFER TO STORAGE

As an alternative to receipt of fuel by railcar, PMEC will be furnished with dock and ship unloading equipment for receipt and unloading of petroleum coke and coal feedstocks from ships. The existing Port of Kalama wharf will be extended by the Port to accommodate vessels delivering feed stock for PMEC. Unloading of the oceangoing vessels will be accomplished by means of a rail-mounted, continuous bucket crane (vertical leg type) ship unloader. The ship unloader will be configured to transfer feedstocks onto the dock conveyor at any point along the working limits of the machine. The crane unloader and dock conveyor will be totally or partially enclosed (depending on final design), with the vent stream containing captured particulate routed to a high-efficiency fabric filter baghouse.

The dock conveyor will be approximately 660 feet in length, with a height of about 27 feet above the top of the dock. A reclaim conveyor reaches into the hold of the ship, and gathers the solid fuel material. This conveyor is partially enclosed to reduce entrainment of dust, and accommodate the entry of material to the conveyor. The reclaim conveyor transfers material onto the dock conveyor. As part of the proposed BACT option, the dock conveyor is to be completely enclosed beyond the load point, and partially enclosed (open-topped with windscreens) for receipt of feed stocks from the ship unloader. The conveyor will terminate in a fully enclosed transfer structure, and the transfer point from the conveyor will be provided with a second fabric filter baghouse for control of captured dusts.

Nominal design capacity for this facility is 4,300 tons per hour (set equivalent to the railcar system for purpose of emission estimates). Significant emissions from the ship unloading facility consist only of particulate matter (PM) and particulates less than 10 microns diameter (PM_{10}). There are two emission units for the ship unloading facility that are included in this BACT analysis:

- Continuous bucket unloader unit; and
- Transfer point to the dock conveyor.
- B-1.10.1 Commercially Available Control Technologies

Based on current practices for solid material handling systems, several types of commercially available control technologies can be identified for the fuel unloading and storage systems at the proposed PMEC facility. An RBLC Database survey indicates that high efficiency fabric filter baghouses, water sprayers, dust suppressants, and enclosures are potential BACT options for ship unloading facilities and the associated transfer of petroleum coke and coal to storage facilities. Baghouse efficiencies varied from 99.0% to 99.9%. In addition, water sprays and various levels of facility and/or conveyor enclosures are also considered to be available control options for PM_{10} emissions. The ranges of fuel handling emission limits for recently permitted sources are as follows:

- PM = 0.0050 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- PM_{10} = 0.0040 gr/dscf to 0.01 gr/dscf (baghouse exhaust limit)
- Opacity = 0% to 10%

B-1.10.2 INFEASIBLE CONTROL MEASURES

Of the identified emission control options for this source, only the complete enclosure of the ship unloading facility would be viewed as technically infeasible. The large size of the entire dock operation, and the need for ship access over water would suggest a very complex and very costly structure, unlike anything currently used in commercial ship unloading.

B-1.10.3 RANKING OF AVAILABLE CONTROL MEASURES

In approximate order of decreasing stringency the feasible control technology options are:

- Effective enclosure of collecting and dock conveyors to the extent practical, with air drawn from enclosures and routed to high-efficiency fabric filters;
- Enclosure of dock conveyor and transfer points, with water or suppressant sprays for dust control;
- Water suppression on collecting conveyor and dock conveyor transfer points.

B-1.10.4 PROPOSED BACT LIMITS AND CONTROL OPTION

PMEC proposes to adopt the most stringent control option among those identified as feasible for this type of particulate emission source. As noted in the discussion of the top-down BACT procedure in the beginning of Section B-1.2, a review of any potential environmental and energy impacts resulting from the implementation of the control option must be addressed, even if the top-ranked control option is chosen. The only potential impact associated with a fabric filter baghouse includes an environmental impact associated with the disposal of existing bags when they are replaced with new bags. This is a relatively minor potential environmental impact, such that use of a fabric filter baghouse is reasonably considered to be the top-ranked control option.

PMEC will adopt a fabric filter performance specification of 99% particulate removal from the airstreams sent to the baghouse. In combination with an estimated particulate collection efficiency of 80% for the entire ship unloading system, this results in 89.2% removal of all particulate emissions associated with this process.

B-1.11 BACT ANALYSIS FOR FEEDSTOCK STORAGE DOME VENT

Both the railcar and ship unloading facilities will supply feedstock via enclosed conveyors to two aluminum dome structures to provide control of fugitive dusts and noise emissions, and an enhanced visual appearance. The fuel storage basis will be a minimum of 30 days of feedstock storage. The upper dome areas will be furnished with low-speed fan powered ventilator units for control and exhaust of heat buildup. The ventilation units will be equipped with power-operated shut-off dampers and will be operated only after the airborne dusts generated within the domes during stockout operations have settled out following each loading period. This limited loading cycle operation was applied to develop a realistic estimate of the maximum potential to emit for this equipment. The unloading equipment for both railcars and ships have higher hourly capacities than that of the gasifier. Thus, the potential to emit for these solids handling sources can be considered to be limited by the capacity of the downstream gasifier system.