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 ≤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

<table>
<tr><th rowspan="2">Proposed BACT</th><th colspan="3">Proposed BACT Emission Limits</th></tr>
<tr><th>PSD Pollutant</th><th>Flare</th><th>Thermal Oxidizer</th></tr>
<tr><td rowspan="5"><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>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>

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:

<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 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:

<u>Pre-Combustion Process Controls</u>
- Chemical Absorption Acid Gas Removal
- Physical Absorption Acid Gas Removal

<u>Post-Combustion Controls</u>
- Flue Gas Desulfurization

➢ ***Evaluate Technical Feasibility***
<u>Chemical and Physical Acid Gas Removal Systems</u>
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.

<u>Flue Gas Desulfurization</u>
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.

[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:

<u>Combustion Process Controls</u>

- Good Combustion Practices

<u>Post Combustion Controls</u>

- SCONOx
- Oxidation Catalysts

➢ ***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 VOC emissions from combustion turbines 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 Catalyst</u>

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:

<u>Combustion Process Controls</u>
- Clean Fuels with Low Potential Particulate Emissions
- Good Combustion Practices

<u>Post-Combustion Controls:</u>
- Electrostatic Precipitation
- Baghouse

➢ ***Evaluate Technical Feasibility***

<u>Clean Fuels with Low Potential Particulate Emissions</u>

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.

<u>Good Combustion Practices</u>

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.

<u>Electrostatic Precipitation</u>

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.

<u>Baghouse</u>

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.

Combustion Process Controls

- Good Combustion Practices

Post Combustion Controls

- Oxidation Catalyst
- $SCONO_x$

➢ ***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. 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.

Oxidation Catalyst

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.

$SCONO_x$

$SCONO_x$ 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.

<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)

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.

<u>Pre-Combustion Control</u>

- Clean Fuels
- Good Combustion Practice

<u>Post-Combustion Control</u>

- Electrostatic Precipitation
- Baghouse

➢ ***Evaluate Technical Feasibility***

<u>Clean Fuels:</u>

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.

<u>Good Combustion Practice:</u>

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

<u>Electrostatic Precipitation:</u>

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.

<u>Baghouse:</u>

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:

<u>Process Controls</u>

- 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***

<u>Forced Air Dust Collection and Control Systems</u>

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.

<u>Dust Suppression Systems</u>

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.