SIERRA CLUB PETITION

EXHIBIT 4

Illinois Environmental Protection Agency
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Project Summary for a Construction Permit Application from Power Holdings of Illinois LLC for a Synthetic Natural Gas Plant near Waltonville, Illinois

Site Identification No.: 081801AAF
Application No.: 07100063
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I. INTRODUCTION

Power Holdings of Illinois LLC (Power Holdings), has submitted an application for a permit to construct a synthetic natural gas (SNG) plant, southeast of Mount Vernon, near Waltonville, in Jefferson County. The plant would use gasification technology to gasify Illinois Basin coal to create pipeline quality gas that would be sold to natural gas suppliers.

Power Holdings must obtain an air pollution control construction permit from the Illinois EPA for the proposed plant because the plant would be a source of emissions. The Illinois EPA has reviewed Power Holdings' application and made a preliminary determination that the application for the proposed project meets applicable requirements. Accordingly, the Illinois EPA has prepared a draft of the construction permit that it would propose to issue for the proposed plant. However, before issuing the permit, the Illinois EPA is holding a public comment period with a hearing to receive comments on the proposed issuance of the permit and the terms and conditions of the draft permit.

II. PROJECT DESCRIPTION

The proposed plant would produce "synthetic" natural gas (SNG) from coal using gasification technology. The nominal capacity of the plant would be about 65 billion cubic feet of SNG per year. The design feedstock for the plant would be Herrin No. 6 coal from Illinois and the plant would use up to 5 million tons of coal per year.

At the plant, coal would be processed in gasifiers to produce a synthesis gas (syngas). The principal components of the syngas would be hydrogen and carbon monoxide. The raw syngas from the gasifiers would be cleaned and then further processed by methanation to produce methane (CH_4). Heat energy generated during the process of gasification, syngas cleaning and methanation is recovered as steam to produce the electric power to operate the plant.

The plant would have six identical gasifiers and two identical gas cleanup trains, each with the capacity to handle half of the raw syngas produced by the gasifiers. The raw syngas from the gasifiers would undergo a series of processes in the gas cleanup trains to remove contaminants from the raw gas and prepare the gas for methanation. The contaminants that would be removed from the raw gas would be entrained particulate matter, mercury, and sulfur compounds and other acid gases from the raw syngas.

The gasifiers convert the coal feedstock into a gaseous stream of syngas by reacting with the coal, water under heat and pressure. A gasifier differs from a combustor, such as a boiler, in that the amount of air or oxygen introduced into the gasifier is limited so that only a relatively small portion of the feedstock is oxidized to provide the heat for the gasification process. Most of the carbonaceous material in the feedstock is chemically broken apart and restructured into the various compounds that make up the syngas.

The gasifiers are designed to operate with oxygen rather than air. Oxygen is provided from an electrically-powered air separation unit. The electrical power used to run the compressors in the air separation unit is provided by steam turbine driven electrical generators located at the plant. Two superheaters, fired on cleaned syngas, will be used to raise the temperature of the steam recovered from high-temperature streams from the gasification process before it enters the steam turbines. In the methanation units, clean syngas, which is now composed of carbon monoxide and hydrogen, is converted into methane, the principal component of natural gas.

Prior to methanation, the H_2S is stripped out of the raw syngas by the Rectisol™ acid gas removal units, which use cold methanol as the adsorption medium. The recovered H_2S is then converted into sulfuric acid in two sulfuric acid plants. The sulfuric acid plants utilize a catalytic reaction for sulfuric acid production. The sulfuric acid plants would be two of the main emission points at the plant. The sulfur dioxide (SO_2) and sulfuric acid mist emissions from the acid plants will be controlled using hydrogen peroxide scrubbers.

The main emission points from the gasification block during normal operation, if carbon dioxide (CO_2) from the gasification block is not otherwise utilized, would be the atmospheric vents from the AGR units. In addition to removing sulfur compounds from the raw syngas, which are sent to the sulfuric acid plants, the AGR units also remove CO_2 from the raw syngas. The CO_2 streams from the AGR units would pass through regenerative thermal oxidizers to control the carbon monoxide (CO) and volatile organic material (VOM) present in these streams, before they are vented. These oxidizers would also convert the remaining sulfur compounds present in these streams to sulfur dioxide (SO_2).

The only direct emissions from the gasification block itself would normally occur from the pilot flames of the syngas and acid gas flares.

During startup, shutdown and certain upsets of a gasifier or a gas processing train, the gasification block would also have emissions from one or more of the flare systems serving the gasification block. Each gas train would have two flare systems, one for flaring any releases of syngas from the train and the other for flaring any releases of H_2S laden acid gas from the AGR unit. Emissions from flaring associated with startup of gasifiers would be minimized as alcohol would be used as the startup feedstock to bring the gasifier up to normal operating pressure before coal is fed into the gasifier. The emissions from flaring would also be minimized through appropriate planning and remedial action to prevent and minimize events that would otherwise necessitate flaring. In addition, flared syngas should typically have undergone cleaning prior to flaring. During normal operation of the gasification block, the only emissions from the flares would be from the pilot burners and flow of purge gas to the flares, which are needed to safely maintain flares in readiness to ignite and combust any syngas or acid gas (i.e., process gases) that are sent to the flares. A more detailed description of the gasification process is provided in Attachment 1.

Other emission units at the proposed plant would include: storage, processing and handling equipment for coal, slag, and other bulk materials; a cooling tower; natural gas-fired auxiliary boiler and burners (used for startup, comfort heating, etc.); various roads and parking areas; and engines for fire pumps and emergency power for the plant.

III. PROJECT EMISSIONS

The potential emissions from the plant are listed below. Potential emissions are calculated based on continuous operation at maximum operation. Actual emissions will be less to the extent that the plant would not operate at its maximum capacity throughout the year.

Pollutant	Potential Emissions (Tons Per Year)
Particulate Matter (filterable)	**65.0**
Sulfur Dioxide (SO_2)	**512.4**
Nitrogen Oxides (NO_x)	**215.6**
Carbon Monoxide (CO)	**777.0**
Sulfuric Acid Mist	**15.9**
Volatile Organic Material (VOM)	**33.0**
Total Reduced Sulfur (TRS)	**4.7**
Methanol	**9.9**
Mercury	**0.0005**
Lead	**0.05**

IV. APPLICABLE EMISSION STANDARDS

All emission units in Illinois must comply with state emission standards adopted by the Pollution Control Board. The state's emission standards represent the basic requirements for sources in Illinois. The various emission units in the proposed plant should readily comply with applicable state standards.

Certain emission units at the proposed plant would be subject to federal New Source Performance Standards (NSPS), at 40 CFR Part 60. The steam superheaters and auxiliary boiler would be subject to the NSPS for Industrial, Commercial, and Institutional Steam Generating Units, 40 CFR 60, Subpart Db. This NSPS generally sets emission limits for emissions of NOx, SO_2 and PM, as well as opacity, from these units. The sulfuric acid plants will be subject to the NSPS for Sulfuric Acid Plants, 40 CFR 60, Subpart H. Coal handling operations would be subject to the NSPS for Coal Preparation Plants, 40 CFR 60 Subpart Y.

V. OTHER APPLICABLE REGULATIONS

A. Prevention of Significant Deterioration (PSD)

The proposed plant is a major new source subject to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. The proposed plant is major for emissions of NO_x, SO_2 and CO with potential annual emissions of more than 100 tons for each of these pollutants. Under the PSD rules, once a proposed source is major for any PSD pollutant, all PSD pollutants whose potential emissions are above the specified significant emission rates in 40 CFR 52.21(b)(23) are also subject to PSD review. Therefore, the proposed plant is also subject to PSD review for $PM_{10}/PM_{2.5}$ and sulfuric acid mist, with potential annual emissions of 77.2 and 15.9 tons, which exceed the significant emission threshold rates of 15/10 and 7 tons per year, respectively. Because emissions of volatile organic materials (VOM) and total reduced sulfur (TRS) compounds will be below their respective significance thresholds of 40 and 10 tons per year, PSD will not apply to these pollutants.

B. Maximum Achievable Control Technology (MACT)

Potential emissions of hazardous air pollutants (HAPs) from the plant are less than 25 tons per year in aggregate and less than 10 tons per year for any single HAP. Therefore, the proposed plant is not a major source of HAPs and is not subject to any MACT standards, either as adopted by USEPA or as determined on a case-by-case basis during permitting pursuant to Section 112(g) of the Clean Air Act. Requirements are proposed in the draft permit for specific units to ensure that the plant is not a major source for HAPs (e.g., use of leak detection and repair for equipment leaks).

C. Acid Rain Program

The proposed plant is not an affected source for purposes of the Acid Rain Program under Title IV of the Clean Air Act. The Acid Rain Program sets certain requirements for control of emissions of SO_2 and NO_x, the pollutants that contribute to acid rain, from electric power plants. The proposed plant will not be an electric power plant under Title IV because generated electricity will be used internally at the plant, with at most a fraction of its electrical power capacity going to the grid.

D. Clean Air Act Permit Program (CAAPP)

This plant would be considered a major source under Illinois' Clean Air Act Permit Program (CAAPP) pursuant to Title V of the Clean Air Act. This is because the plant would be a major source for purposes of the CAAPP because it is a major source for purposes of the PSD program. Power Holdings would have to apply for a CAAPP permit within 12 months of commencing operation.

VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Under the PSD rules, an applicant for a permit must demonstrate that Best Available Control Technology (BACT) will be used to control emissions of pollutants subject to PSD. Power Holdings has provided a BACT demonstration in its application addressing emissions of pollutants that are subject to PSD, i.e., NO_x, SO_2, CO, $PM/PM_{10}/PM_{2.5}$ and sulfuric acid mist.

BACT is defined by Section 169(3) of the federal Clean Air Act as:

> An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental and other costs, determines is

achievable for such facility through application of production processes and available methods, systems and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

BACT is generally set by a “Top Down Process.” In this process, the most effective control option that is available and technically feasible is assumed to constitute BACT for a particular unit, unless the energy, environmental and economic impacts associated with that control option are found to be excessive. In addition to the BACT demonstration provided by an applicant in its permit application, a key resource for BACT determinations is USEPA’s RACT/BACT/LAER Clearinghouse (USEPA Clearinghouse), a national compendium of control technology determinations maintained by USEPA. Other documents that are consulted include general information in the technical literature and information on other similar or related projects that are proposed or have been recently permitted. A summary of the proposed BACT determination for this project is provided in Attachment 2.

A. BACT Discussion for Project Design:

The stated objective of Power Holdings for this project is to produce and sell synthetic natural gas. Location of this plant near ample supplies of suitable coal and adequate water is critical. The location of the proposed plant in southern Illinois meets these objectives. This dictates development of the plant at a site that is served by existing natural gas pipelines to have access to the markets for natural gas in Illinois.

The feedstock selected for the gasifiers and associated equipment is Illinois #6 coal. In contrast to Powder River Basin (PRB) coal from the west, Illinois #6 coal contains more carbon per Btu, the primary constituent of methane (CH_4), which itself is the primary component of natural gas. In addition, due to the gas cleanup in the gasification block, sulfur within Illinois #6 coal will be very well controlled, so that the sulfur content of the feedstock has little effect on plantwide SO_2 emissions (particularly including sulfur converted into sulfuric acid).

Gasification plants are normally designed for specific purposes and feedstocks. Gasification technologies designed by the same provider may also vary depending on the product, whether it is synthetic natural gas (SNG) or electricity (Integrated Gasification Combined Cycle, or IGCC). A GE Technologies’ water quench system may be used at an SNG plant whereas GE technologies’ radiant syngas cooler may be better suited at an IGCC plant.

B. BACT Discussion for the Gasification Block - Syngas Cleanup:

The following discussion addresses BACT as it is provided by cleanup of raw syngas in the gasification block. This cleanup removes substances from the raw syngas that would otherwise directly lead to emissions when the syngas was used as fuel in the superheaters at the plant and burned. In the absence of adequate “pre-combustion” cleanup of the raw syngas, the emissions of these pollutants from the superheaters would be such that they would have to be controlled with post-combustion emission control devices, as used on solid-fuel fired boilers.

Particulate Matter (PM)

The gasification process is potentially a source of particulate matter emissions from the slag that is formed from the ash material in the feedstock. The majority of the slag produced by gasification is coarse slag, which would be captured within the gasifiers and contained and not entrained in the syngas.

The fine slag, which is entrained in the raw syngas, must be removed from the raw syngas prior to processing in downstream units due to the operational requirements of these units. The entrained particulate must also be removed from the raw syngas to meet the requirements for pipeline quality gas. There are two basic approaches for the cleaning of raw syngas to remove particulate: scrubbing with water and filtration. Each approach achieves a similar level of performance for PM and the selection of approach is largely a consequence of the gasification technology that has been selected rather than a difference in the resulting emission levels.

Consistent with the approach taken to syngas cleanup by General Electric, the gasification technology supplier for the proposed plant, Power Holdings has proposed to use water scrubbing for control of PM emissions. The ability of countercurrent scrubbing to achieve significant removal of fine particulate and water-soluble contaminants from raw syngas to the wash stream is well demonstrated.

Filtering of raw syngas can also be performed with dry ceramic or metallic candle filters, which are normally located upstream of the high-temperature heat recovery devices. Barrier filters produces a dry solid as compared to the wet waste from a scrubbing system, as discussed above. The controlled levels of PM emissions achieved by candle filters are similar to those achieved by scrubbers. However, the filters are subject to blinding or breakage, as discussed in several of the status reports for the Wabash River IGCC demonstration project. Dry filtration is also not effective at removing hydrogen chloride as wet scrubber systems. Finally, dry material collected by a filter is not as easily handled as the wet stream with scrubbing. Because scrubbing and filtration achieve similar levels of PM emissions and filtration poses certain operational concerns for the plant, the Illinois EPA is proposing to accept scrubbing, as proposed by Power Holdings, as the underlying control technology for BACT for PM emissions.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist

As already discussed, sulfur compounds are present as a contaminant in the raw syngas from gasification, as sulfur is present in the feedstock and carried over into the syngas. These sulfur compounds, primarily H_2S and COS, must be removed from the syngas prior to methanation. At SNG plants, this occurs in the Acid Gas Removal (AGR) Units.

There are currently three basic absorption processes available for Acid Gas Removal (AGR) Units to remove sulfur compounds from the raw syngas stream: Selexol™, Rectisol™, and amine-based processes. The stripping step present with all three processes produces a concentrated stream of sulfur compounds, referred to as "acid gas," that is then processed in a sulfuric acid plant or sulfur recovery plant.

The Selexol™ process uses a solvent made of dimethyl ether or polyethylene glycol. The Rectisol™ process uses cold methanol as the solvent. Both processes involve physical absorption relying upon pressure to dissolve sulfur compounds in the adsorption solvent. These sulfur compounds are then removed from the solvent in a separate step, by depressurization of the solvent in a stripper, and the clean, regenerated solvent is returned to the absorption column.

In amine absorption processes, sulfur compounds in the feed gas are removed by a chemical reaction or bond between the sulfur compounds and an amine in a water solution. The amine solution is then regenerated in a separate step with heat in a stripper tower. Methyldiethanolamine (MDEA) is the most commonly used amine in these systems. Amine absorption is routinely used at petroleum refineries (for control of sulfur compounds in refinery fuel gas).

The most effective control technology options for the proposed plant are the Selexol™ and Rectisol™ processes. Both processes are capable of removing over 99 percent of the sulfur compounds from the syngas. The feasibility studies performed by vendors of these processes indicate that Selexol™ can achieve 99.8 percent nominal removal of sulfur from the raw syngas and Rectisol™ can possibly achieve 99.9 percent nominal removal. Power Holdings has selected a Rectisol™ system for the proposed plant because Rectisol™ will be more effective in removing sulfur compounds from the raw syngas.

The Illinois EPA is proposing removal of sulfur compounds in the raw syngas using the Rectisol™ process or equivalent as BACT for control of the emissions of SO_2 and sulfuric acid mist that would accompany combustion of syngas in the superheaters at the plant.

C. BACT Discussion for the Gasification Block - AGR Unit Vents

Carbon Monoxide (CO)

In the event that the carbon dioxide (CO_2) from the gasification block is not otherwise utilized, the (uncontrolled) emissions of CO, which are present in the CO_2 streams from the AGR unit vents, would have to be controlled. Flares, thermal afterburners (without heat recovery), catalytic afterburners, and afterburners with heat recovery were examined for feasibility. Flares and non-recovery thermal afterburners, while attempting to reduce CO emissions, would also promote the generation of NO_x since substantial amounts of supplemental fuel or auxiliary fuel would be required. Catalytic afterburners, while being able to operate at generally lower operating temperatures than oxidizers that incorporate heat recovery, would nevertheless operate at temperatures higher than the syngas vented to it. Accordingly, these technologies were not considered further. To control CO emissions most effectively, afterburners or oxidizers with heat recovery would have to be utilized. The resulting BACT level of control for CO is proposed to be set at 10 ppm.

Nitrogen Oxides (NO_x)

Emissions of nitrogen oxides (NO_x) are generated by the oxidizers that control the AGR Unit Vents. These NO_x emissions are associated with the combustion of auxiliary fuel in the oxidizers. Emissions of NO_x are minimized by use of regenerative thermal oxidizers. This type of oxidizer minimizes NO_x emissions as it has higher thermal efficiency and lower auxiliary fuel consumption than other types of thermal oxidizers that could be used to control the CO in this gas stream, as discussed above.

The emissions of NO_x generated from the combustion of pilot gas and process gas in the flares are addressed in the following section, which discussed BACT for the flares.

D. BACT Discussion for Gasification Block – Startup Shutdown and Malfunction

The above BACT discussions address normal operation of the gasification blocks. Emissions that are generated during startup, shutdown and malfunction from the gasification block are vented to a flare, so BACT must be established for flaring. “Off-specification” syngas, as would be produced during startup, shutdown or malfunction of the gasifiers must be safely disposed of by flaring and cannot be processed into SNG. Incidentally, even though off-specification gas must be flared, it is expected that most flared syngas will still have been subjected to some level of gas cleanup, especially as PM cleanup with water scrubbing is the initial step in the cleanup of syngas. There also may be events in which a malfunction of the methanation process requires firing of cleaned syngas. Work practice requirements and secondary emission limits are proposed as BACT to address startup, shutdown and malfunction.

The required BACT work practices for startup, shutdown and malfunction are intended to assure that appropriate measures are taken to minimize emissions from startup, shutdown and malfunction. For this purpose, the draft permit establishes certain basic measures that must be used to minimize emissions. It also establishes a general approach to minimization of emissions through formal operating and maintenance procedures and flare minimization planning, which may be refined based on actual operating experience at the plant. One key element of the basic measures for startups is that natural gas and alcohol must be used for pre-heating and startup of gasifiers. Another key aspect of BACT for flares is operating in accordance with good air pollution control practices, as defined by 40 CFR 60.18, to ensure effective destruction of CO, organic compounds and reduced sulfur compounds present in gas streams that are being flared.

The emission limits that are set as secondary BACT for periods of startup, shutdown and malfunction are expressed in pounds per hour and tons per year. They are imposed to protect air quality. They set a cap or ceiling on allowed emissions, consistent with USEPA guidance for setting BACT for periods of startup, shutdown and malfunction. A number of factors preclude imposition of BACT limits expressed in pounds per million Btu during such periods. These include: 1) the complexity of an SNG plant, in which syngas is produced for immediate transfer to the pipeline, 2) the stringent levels of control that are normally required of the units, and 3) the limited operational experience with SNG plants. An approach to these periods is needed that recognizes the inherent technological aspects of gasification and associated syngas cleanup technologies to provide comparable control of emissions during periods of startup, shutdown and malfunction, as compared to periods of normal operation.

E. BACT Discussion for the Sulfuric Acid Plants

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist

SO_2 and sulfuric acid mist are emitted from the sulfuric acid production process. The process consists of the following steps: (1) combustion of sulfur compounds into SO_2, (2) conversion of SO_2 and oxygen into SO_3, (3) hydrolysis of the SO_3 or reaction with water to form sulfuric acid. Unreacted SO_2 is emitted from the exhaust from the sulfuric acid plant, along with small amounts of sulfuric acid mist not captured as product.

Following the top-down BACT process, Power Holdings started by looking at available add-on control technologies for reducing SO_2 and sulfuric acid mist ("flue gas desulfurization"). These include: wet scrubbing, regenerable wet scrubbing, "dry scrubbing" or spray dryer absorber, combined dry and wet scrubber, circulating dry scrubber, duct sorbent injection, furnace sorbent injection, limestone injection dry scrubbing, and hydrogen peroxide wet scrubber with a mist eliminator.

The add-on control technology deemed to be feasible was scrubbing using a hydrogen peroxide solution. Technologies, such as dry scrubbing (all types), duct sorbent injection, or furnace sorbent injection, were deemed infeasible as they are effective when applied to these sulfuric acid plants given the low concentration of SO_2 and sulfuric acid mist in the exhaust and the low temperature of the exhaust.

Furnace sorbent injection technologies are not technically feasible since there is no "furnace" in the sulfuric acid plant. Wet or dry limestone or lime scrubber systems are not technically feasible since the gas temperatures are too low and the SO_2 and H_2SO_4 concentrations are too low for that type of scrubber technology to work effectively.

Because the SO_2 concentration in the exhaust is below 1000 parts per million, dry scrubbing is much less effective, whereas hydrogen peroxide scrubbers are better suited to control emissions of SO_2.

A scrubbing system which utilizes hydrogen peroxide as the reactant is selected as the control method based not only on its superior performance for control of SO_2, but also because its use helps to facilitate the production of sulfuric acid itself. This is specifically due to the far more superior contact made between the SO_2 and the hydrogen peroxide, relative to other control technologies. The proposed scrubbing system represents the top control technology for the sulfuric acid plants. The proposed SO_2 BACT limit is established at 1.41 lb SO_2/ton of sulfuric acid produced (30 day rolling average) and 0.06 lb H_2SO_4/ton of sulfuric acid produced (24-hour average).

Nitrogen Oxides (NO_x)

NO_x in formed in the sulfuric acid plant when elemental nitrogen and oxygen in the combustion air combine within the high temperature environment of the combustion zone. Power Holdings started by looking at available add-on control technologies for reducing NO_x. These include: low-NO_x burners, selective catalytic reduction (SCR), and selective noncatalytic reduction (SNCR).

Low-NO_x burners have not been designed for the types of burners used on sulfuric acid plants and so were deemed infeasible.

Selective catalytic reduction (SCR) uses a chemical reaction to remove NO_x from the exhaust gas. The reaction between gaseous NO_x and a reagent, i.e., ammonia (NH_3), as it passes through a porous ceramic bed or screen impregnated with catalyst, reduces NO_x back to N_2. This reaction, which takes place in a temperature range of 575°F to 750°F, is considered very effective in controlling NO_x. The temperature of exhaust gas from combustion will be within this temperature range, making use of SCR suitable.

SNCR is a flue gas treatment system that reduces post-combustion NO_x emissions using ammonia or urea injection, similar to SCR but without a catalyst. However, in the absence of a catalyst, higher temperatures in the range 1600 to 2000°F are required for ammonia to selectively react with nitric oxide to form molecular nitrogen and water. Maintaining the desired temperature window is, therefore, one of the most important operating and design considerations. Since SNCR does not use a catalyst, additional ammonia must be used to achieve higher levels of NO_x control, resulting in a greater potential for ammonia slip.

When both SNCR and SCR are applicable, SCR typically is considered more efficient in reducing NO_x, ranging from 60 to 90% for SCR and up to 60% for SNCR. SCR is considered BACT for emissions of NO_x from the sulfuric acid plants. The proposed BACT limit is 0.031 lb/million Btu on a 30-day rolling average basis, equivalent to 0.16 lb/ton of 100 percent sulfuric acid produced.

F. BACT Discussion for the Steam Superheaters:

Nitrogen Oxides (NO_x)

The superheaters emit NOx, which is formed thermally from nitrogen contained in the ambient air that is introduced into the units as combustion air. The following emission control technologies were generally reviewed as possible control options for NO_x, in order from most effective to least effective: 1) Low-NO_x burners, 2) Overfire air, 3) Flue gas recirculation, 3) Selective catalytic reduction (SCR), 4) Selective noncatalytic reduction (SNCR), 5) SCONOX and 6) THERMALONOX.

Low-NO_x combustors are a control technique used mostly for natural gas fired combustion. However, this technique is not available for low-Btu syngas-fired superheaters, as there would be no furnace section to provide required residence time. In the absence of such a furnace, low-NO_x burners would interfere with stable combustion. The same lack of a wet scrubber or furnace to provide residence time, renders THERMALONOX technology (a variant of low-NO_x burners), overfire air and flue gas recirculation infeasible as well.

SCONOx™ uses a potassium carbonate coated catalyst to reduce emissions of oxides of nitrogen, typically from natural gas-fired, water injected turbines. The catalyst oxidizes carbon monoxide to carbon dioxide, and nitric oxide (NO) to nitrogen dioxide. The carbon dioxide is exhausted while the nitrogen dioxide adsorbs onto the catalyst to form potassium nitrites and potassium nitrates. Dilute hydrogen gas is passed periodically across the surface of the catalyst to regenerate the coating. The regeneration cycle converts the potassium compounds back to potassium carbonate, water, and elemental nitrogen. The potassium carbonate is thereby made available for further adsorption and the water and nitrogen are exhausted. There are no SCONOX guarantees when applied to units fired on syngas, such as the superheaters.

Selective catalytic reduction (SCR) uses a chemical reaction to remove NO_x from the exhaust gas. The reaction between gaseous NO_x and a reagent, i.e., ammonia (NH_3), as it passes through a porous ceramic bed or screen impregnated with catalyst, reduces NO_x back to N_2. This reaction, which takes place in a temperature range of 575°F to 750°F, is considered very effective in controlling NO_x. The temperature of exhaust gas from combustion will be within this temperature range, making it a suitable application for SCR. SCR is not a demonstrated technology for control of NO_x emissions from gas-fired steam generating units because of catalyst contamination.

SNCR is a flue gas treatment system that reduces post-combustion NO_x emissions using ammonia or urea injection, similar to SCR but without a catalyst. However, in the absence of a catalyst, higher temperatures in the range 1600 to 2000°F are required for ammonia to selectively react with nitric oxide to form molecular nitrogen and water. Maintaining the desired temperature window is, therefore, one of the most important operating and design considerations. Since SNCR does not use a catalyst, additional ammonia must be used to achieve higher levels of NO_x control, resulting in a greater potential for ammonia slip.

The use of SCR is considered BACT for emissions of NO_x from the steam superheaters. The proposed BACT limit is 0.035 lb/million Btu on a 30-day rolling average basis. The format of these limits (lb million Btu (HHV) of heat input to the unit) is selected to be consistent with the format used by USEPA in the NSPS for steam generating units, 40 CFR 60, Subpart Db, which would be applicable to the superheaters and auxiliary boiler. This same format is used in conjunction with the BACT limits described below.

There are no comparable superheaters or fuel-types (high hydrogen and CO) listed in the RBLC for comparison but there are comparable gas-fired heaters listed.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

In the syngas cleanup system, the sulfur content of raw syngas is reduced by over 99%, so that these units which utilize cleaned syngas as fuel will be firing very low sulfur fuel. While the following technologies were evaluated: wet scrubbing spray dryer absorber (dry scrubber), combined dry and wet scrubbing, circulating dry scrubber, dry scrubber, duct sorbent injection, furnace sorbent injection and limestone injection dry scrubbing, the sulfur concentrations are so low in the syngas fuel for the superheaters that post-combustion SO_2 sulfuric acid mist control ("flue gas desulfurization") would not be effective in any case.

For burning of syngas, BACT for SO_2 is proposed to be set at 0.0013 lb/million Btu, based on a 24-hour block average.

Particulate Matter (PM)

The syngas fired in the superheaters, as far as particulate matter is concerned, is "clean" insofar as the concentration of PM is relatively small, similar to that of natural gas. While the following technologies were evaluated as possible controls: baghouse, electrostatic precipitators (including wet ESP), wet scrubber, Venturi scrubber and cyclone, the fact that the gas is virtually clean of PM, use of any add-on controls would be of questionable effectiveness to further control emissions and very costly. The use of the syngas cleanup for particulate is sufficient to render the gas burned in the superheater as clean.

For burning of syngas, BACT for PM is prposed to be set at 0.01 lb/mmBtu, based on a 24-hour block average.

Carbon Monoxide (CO)

Emissions of CO are the product of incomplete combustion. The possible control methods are excess air, design of the combustion process and good combustion practices to minimize the formation of CO, flaring, afterburning, and oxidation (catalytic and thermal).

A large amount of excess air in the superheaters could theoretically reduce CO emissions by raising the amount of oxygen available to provide more complete oxidation of CO. Use of this technique would have the adverse environmental impact of increasing emissions of other pollutants, particularly thermal NO_x, which is supported by excess air.

Power Holdings proposes proper operation and maintenance in combination with a CO emission limit of 0.04 lb/million Btu based on a 30-day rolling average to be BACT for the units.

G. BACT Discussion for the Auxiliary Boiler

The auxiliary boiler is a natural gas-fired boiler used to support the operation of the plant. The boiler would provide steam to the steam turbine-generators to the gasification block during startups and steam for freeze protection and area comfort heating when the plant is not operating. Given its function, the auxiliary boiler will operate for at most 4000 hours per year after the plant begins operation.

As the auxiliary boiler would be fired with natural gas, BACT is provided for emissions of SO_2 and PM. Given the nature of this boiler, including infrequent and intermittent operation, additional add-on control measures are not practical or cost-effective. For example, in the case of SO_2, scrubbing would not achieve a lower SO_2 emission rate than that already provided by use of natural gas given the very low concentration of SO_2 in the exhaust.

Power Holdings considered various control technologies to control NO_x and CO emissions of the auxiliary boiler. Since natural gas will be the only fuel fired in the auxiliary boiler, good combustion practices are proposed as BACT for CO and additionally, low-NO_x burners and flue gas recirculation for NO_x.

The proposed BACT limits are 0.035 lb/mmBtu (24-hour block) for NO_x, 0.040 lb/mmBtu (24-hour block) for CO, 0.0013 lb/mmBtu (24-hour block) for SO_2, and 0.010 lb/mmBtu (24-hour block) for PM for the auxiliary boiler.

H. BACT Discussion for Natural Gas-Fired Burners

The startup burners are natural gas-fired units that will be utilized before startup for pre-heating gasifiers and the CO shift and methanation units in the gas processing trains. As such, the preheat burners would be idle most of the time.

Power Holdings considered various feasible technologies for these burners for NOx, CO, SO_2 and PM/PM_{10}, but since natural gas will be the only fuel fired in them, then for these burners, good combustion practices are proposed as BACT for CO and NOx, and the use of natural gas for SO_2 and PM. Given the nature of these units, including infrequent and intermittent operation of the startup burners, additional add-on control measures are not practical and/or cost-effective. The proposed BACT limits for the gasifier burners are 0.20 lb/mmBtu (24-hour average) for NOx and 0.10 lb/mmBtu (3-hour average) for CO. The proposed limits for the process unit burners are 0.080 lb/mmBtu (24-hour average) for NOx and 0.040 lb/mmBtu (3-hour average) for CO. BACT limits are proposed for only NOx and CO as needed to address the performance of the burners for the pollutants that are affected by combustion, namely, NOx and CO.

I. BACT Discussion for the Cooling Tower

A cooling system is used to condense very low pressure “exhaust” steam after it leaves the steam turbine generator and recover the water for reuse in the steam cycle. Power Holdings has proposed a wet cooling tower, in which cooling is achieved by evaporation of water. High-efficiency drift eliminators and dry cooling were considered for controlling PM emissions from the cooling tower.

Direct dry cooling systems use air to directly condense steam, whereas indirect dry systems use a closed loop water system to condense steam and the resulting heated water is then air cooled. Such dry cooling systems transfer heat to the atmosphere without significant loss of water. However, these systems require a large amount of power to operate the many fans needed to move the air through the unit. There can also be nuisance noise associated with these fans. The extra equipment needed and the significant increase in parasitic electricity consumed to operate that equipment acts to increase emissions of a plant, as additional fuel must be consumed to supply this electricity. This renders dry cooling inappropriate when the location of a proposed project and available water resources make it amenable to wet cooling.

Because dry cooling has been rejected as a control technology option for the cooling tower, the use of high-efficiency drift eliminators is proposed as BACT for the cooling tower. High-efficiency drift eliminators act to control PM emissions by minimizing the drift or loss of water droplets from the cooling tower. These droplets are the source of PM emissions from a cooling tower, since mineral material present in the droplet is emitted as PM when an entire droplet escapes the cooling tower and completely evaporates in the atmosphere.

J. BACT Discussion for Material Handling

Power Holdings has proposed a variety of measures, including use of baghouses and implementation of work practices to control both so-called “stack” and “fugitive” emissions, from handling of material with the potential to generate dust. The proposed BACT determination for PM emissions from coal and slag handling is intended to require that PM emissions be effectively controlled while still providing appropriate operational flexibility in the manner with which this is accomplished in practice by the plant. This general approach has been taken because of the Illinois EPA’s experience with material handling operations and associated control measures at coal-fired power plants, which is that these operations change over time as equipment ages and new systems, devices, and techniques become available. These types of changes can also occur during the detailed design and construction of a project, as new approaches to material handling operations are identified and impediments to the initial plans are identified.

Accordingly, material handling operations at the proposed plant are most efficiently and consistently addressed from an administrative perspective through establishment of generic BACT control requirements, rather than with separate requirements for each individual operation.

For this purpose, the draft permit delineates two categories of material handling operations: 1) Dry material handling, and 2) handling of wet materials. BACT for the first category of operations, handling of dry materials, is proposed as enclosure to prevent visible emissions. In addition, if PM emissions are aspirated to a control device, a filter or baghouse device must be used unless consideration of operational safety dictates another type of control device. This approach has been taken as filtration is generally considered the most effective active control technology for control of dust from material handling operations if it does not present safety concerns from the accumulation of combustible dust. Filters control PM emissions by passing dust-laden air through a bank of filter tubes suspended in the gas flow stream. A filter "cake", composed of captured particulate, builds up on the "dirty" side of the filter. Periodically, the dust cake is removed through a physical mechanism (e.g., a blast of compressed air from the "clean" side of the filter), which causes the dust to fall into a hopper or back into the silo. The proposed approach for this category of operations requires very effective control of PM emissions, as control of fugitive emissions is addressed by the prohibition against visible emissions and control of stack emissions is addressed by the requirements and minimum performance specifications for control devices.

For handling of wet materials, the performance standard proposed as BACT is absence of visible emissions, accompanied by timely collection of any spilled material that could become airborne after it dried. Aspiration of dust to control devices is not addressed as the moisture in the material must be sufficient to prevent direct emissions. This approach allows a variety of suppression or elimination techniques to be used along with the moisture present in a material, including partial or total enclosure and compaction and/or chemical or wet suppression, as appropriate, to address the handling of particular wet materials. This approach requires very effective control of PM emissions from wet material handling operations, as control of fugitive emissions is addressed by the prohibition against visible emissions and the further requirement to take actions to prevent secondary emissions from spilled material.

K. BACT Discussion for Roadways and Open Areas

Power Holdings has proposed a variety of measures, including paving (roadways), sweepers and vacuum trucks, to control emissions of fugitive dust from truck traffic on plant roads. The proposed BACT determination for roadways is intended to require that these emissions be effectively controlled while still providing appropriate operational flexibility in the manner with which this is accomplished in practice by the plant. This general approach has been taken because of the Illinois EPA's experience with fugitive dust control programs. This experience indicates that dust control programs must be flexible to appropriately respond to changing operation and the weather (rain, hot, dry weather in the summer, and snow and ice in the winter). In addition, dust control programs change and evolve over time as new control techniques and service providers become available to control emissions. Accordingly, like material handling operations, roadways at the proposed plant are most appropriately addressed through establishment of broad BACT control requirements, rather than with detailed, prescriptive requirements for control of emissions.

For this purpose, the draft permit proposes two types of BACT requirements for roadways, an opacity requirement and a number of work practice requirements. First, control measures must be used such that opacity of emissions from truck traffic on roadways and windblown dust does not exceed 15 percent. (This requirement would not apply during high wind speed, defined as wind speed in excess of 25 miles per hour, as provided by 35 IAC 212.314.) Second, the required work practices for control of fugitive dust must include: 1) paving of regularly traveled roads and 2) handling of collected dust in a manner that prevents it from being released back into the environment. This approach requires very effective control of PM emissions from roadways, as control of emissions is addressed both by a numerical opacity standard, which may readily be enforced by any qualified opacity observer and by specific requirements and performance standards for the fugitive dust control program.

L. BACT Discussion for Emergency Engines

Emergency engine must be installed at the plant to provide reserve power for essential services during interruptions in the electrical supply system and in the event of a fire or other emergency. These engines will have to meet the emission standards of the New Source Performance Standard (NSPS) for various categories of new internal combustion engines. For emergency engines that must have a dedicated reserve supply of fuel, BACT will be provided as ultra low-sulfur fuel must be used and operation is limited to 500 hours per year unless specifically authorized by the Illinois EPA. Due to the use of ultra low-sulfur fuel, there will be both minimal annual emissions and lb/mmBtu emission rates for SO_2 from the engines. For any engines that will operate for more than 500 hours per year, BACT will be provided as the engines will be required to use natural gas as fuel.

VII. AIR QUALITY ANALYSIS

A. Introduction

The previous discussions addressed emissions and emission standards. Emissions are the quantity of pollutants emitted by a source, as they are released to the atmosphere from various emission units. Standards are set limiting the amount of these emissions as a means to address the presence of contaminants in the air. The quality of air as we breathe it or as plants and animals experience it is known as ambient air quality. Ambient air quality considers the emissions from a particular source after they have dispersed following release from a stack or other emission point, in combination with pollutants emitted from other nearby sources and background pollutant levels.

The concern for pollutants in ambient air is typically expressed in terms of the concentration of the pollutant in the air. One form of this expression is parts per million. A more common scientific form is microgram per cubic meter, which is a millionth of a gram in a cube of air one meter on a side.

The United States EPA has established standards for the level of various pollutants in the ambient air. These ambient air quality standards are based on a broad collection of scientific data to define levels of ambient air quality where adverse human health impacts and welfare impacts may occur. As part of the process of adopting air quality standards, the USEPA compiles scientific information on the potential impacts of the pollutant into a "criteria" document. Hence the pollutants for which air quality standards exist are known as criteria pollutants. Based upon the nature and effects of a pollutant, appropriate numerical standards(s) and associated averaging times are set to protect against adverse impacts. For some pollutants several standards are set, for others only a single standard has been established.

Areas can be designated as attainment or nonattainment for criteria pollutants, based on the existing air quality. Areas in which the air quality standard is met for a pollutant are known as attainment areas. If the air quality standard is exceeded, the area is designated as nonattainment. Given the geographic extent of areas designated as nonattainment and the USEPA's process for redesignating an area to attainment, the air quality in some or all of an area designated as nonattainment may actually be in compliance with the relevant air quality standard.

In attainment areas the goal is to generally preserve the existing clean air resource and prevent increases in emissions which would result in nonattainment. In a nonattainment area efforts must be taken to reduce emissions to come into attainment. An area can be attainment for one pollutant and nonattainment for another.

Compliance with air quality standards is determined by two techniques, monitoring and modeling. In monitoring, one actually samples the levels of pollutants in the air on a routine basis. This is particularly valuable as monitoring provides data on actual air quality, considering actual weather and source operation. The Illinois EPA operates a network of ambient air monitoring stations across the state.

Monitoring is limited because one cannot operate monitors at all locations. One also cannot monitor to predict the effect of a future source, which has not yet been built, or to evaluate the effect of possible regulatory programs to reduce emissions. Modeling is used for these purposes. Modeling uses mathematical equations to predict ambient concentrations based on various factors, including the height of a stack, the velocity and temperature of exhaust gases, and weather data (speed, direction and atmospheric mixing).

Modeling is performed by computer, allowing detailed estimates to be made of air quality impacts over a range of weather data. Modeling techniques are well developed for essentially stable pollutants like particulate matter, NO_x, and CO, and can readily address the impact of individual sources. Modeling techniques for reactive pollutants, e.g., ozone, are more complex and have generally been developed for analysis of entire urban areas. They are not applicable to a single source with small amounts of emissions.

Air quality analysis is the process of predicting ambient concentrations in an area or as a result of a project and comparing the concentration to the air quality standard or other reference level. Air quality analysis uses a combination of monitoring data and modeling as appropriate.

B. Air Quality Analysis for NO_2, SO_2, PM_{10} and CO

An ambient air quality analysis was conducted by a consulting firm on behalf of Power Holdings to assess the impacts of the proposed plant on ambient air quality. Under the PSD rules, this analysis must demonstrate that the proposed project will not cause or contribute to a violation of any applicable air quality standard or PSD increment.

The starting point for determining the extent of the modeling necessary for this facility was evaluating whether the proposed plant would have a “significant impact”. The PSD rules identify Significant Impact Levels, which represent thresholds triggering a need for more detailed modeling. These thresholds are specified for all criteria pollutants, except ozone and lead. The significant impact levels do not correlate with health or welfare thresholds for humans, nor do they correspond to a threshold for effects on flora or fauna.

The Illinois EPA performed selected audit modeling runs to verify the applicant’s results for the preliminary impact analysis and overall impact analysis. The accompanying tables (Tables 1 and 2) summarize the results.

TABLE 1: PRELIMINARY IMPACT ANALYSIS (μg/m^3)
(SIGNIFICANT IMPACT ASSESSMENT)

Pollutant	Averaging Period	Maximum Modeled Concentration[a]	Significant Air Quality Impact Level	NAAQS
NO_2	Annual	0.78	1	100
SO_2	3-Hour	11.00	25	1,300
	24-Hour	4.41	5	365
	Annual	0.59	1	80
PM_{10}	24-Hour	4.47	5	150
	Annual	0.93	1	50
CO	1-Hour	32.40	2,000	40,000
	8-Hour	11.90	500	10,000

Notes:

a. High 1st high value based upon individual evaluation of each year of a 5-year meteorological dataset.

The preliminary impact analysis showed maximum concentrations for all emissions that are less than applicable significant impact levels. Therefore, no further analysis with modeling of either the proposed plant or existing sources in the area is necessary.

Consideration was also given to the background levels of air quality, as determined at ambient monitoring stations operated by the Illinois EPA. This full impact analysis yielded concentrations that were in compliance with the PSD increments as is demonstrated in Table 2 below.

TABLE 2: OVERALL AIR QUALITY IMPACT ASSESSMENT (μg/m^3)

Pollutant	Averaging Period	Background Air Quality	Maximum Modeled Concentration	Overall Concentration	NAAQS
NO_2	Annual	30	0.78	30.8	100
SO_2	3-Hour	692	11.0	703	1,300
	24-Hour	190	4.41	194	365
	Annual	16	0.59	16.6	80
PM_{10}	24-Hour	57	4.47	61.5	150
	Annual	24	0.93	24.9	50
CO	1-Hour	5828	32.4	5,660	40,000
	8-Hour	1778	24.9	1,803	10,000

C. Vegetation and Soils Analysis

Holdings provided an analysis of the impacts of the proposed plant on vegetation, animals, and soils, and on emissions impacts resulting from residential and commercial growth associated with construction of the proposed plant (“additional impact analysis”).

The first several steps in this process focus on the use of modeled air concentrations and published screening values for evaluating exposure to flora from selected criteria pollutants (SO_2, NO_x, CO, ozone and PM_{10}).

The proposed plant's emissions are not expected to result in harmful effects to the soils and vegetation in the area. Maximum modeled impacts for SO_2, NO_x, CO and PM_{10} do not exceed the secondary NAAQS level set forth by USEPA. Maximum modeled 3-hour average SO_2 impacts do not exceed the significant impact levels.

E. Construction and Growth Analysis

Power Holdings provided a discussion of the emissions impacts resulting from residential and commercial growth associated with construction of the proposed plant ("additional impact analysis"). Anticipated emissions resulting from residential, commercial, and industrial growth, associated with construction and operation of the proposed plant, are expected to be low. Despite the large number of workers required during the construction phase and a significant number of permanent employees for operation of the plant, emissions associated with new residential construction, commercial services, and supporting secondary industrial services are not expected to be significant. To the extent that the plant draws from the existing workforce and is supported by the existing infrastructure, impacts would be minimal and distributed throughout the region.

VIII. DRAFT PERMIT

The Illinois EPA has prepared a draft of the construction permit that it would propose to issue for this plant. The conditions of the permit would set forth the permitted emissions of the plant and the emission control requirements that the plant must meet. These requirements include the applicable emission standards that apply to the various units at the plant, such as the measures that must be used and the emission limits that must be met as BACT for emissions of SO_2, NOx, CO, $PM/PM_{10}/PM_{2.5}$ and sulfuric acid mist from the project. They also include the measures that must be used and the emission limits that must be met for emissions of different regulated pollutants from the plant.

Limitations are set for each pollutant for which the project is major under PSD, and for pollutants for which the project is not major. In addition to annual limitations on emissions, the permit includes short-term emission limitations and operational requirements, as needed, to provide practical enforceability of the annual emission limitations. As previously noted, actual emissions associated with the plant would be less than the permitted emissions to the extent that control equipment normally operates to achieve emission rates that are lower than the applicable standards and limitations.

The permit also establishes appropriate compliance procedures for the project, including requirements for emission testing, required work practices, operational monitoring, recordkeeping, and reporting. These measures are imposed to assure that the operation and emissions of the plant are appropriately tracked to confirm compliance with the various limitations and requirements established for individual emission units.

IX. REQUEST FOR COMMENTS

It is the Illinois EPA's preliminary determination that the permit for the proposed plant meets applicable state and federal air pollution control requirements. The Illinois EPA is therefore proposing to issue a construction permit for the plant. Comments are requested on this proposed action by the Illinois EPA and the conditions of the draft permit.

Attachment 1 - Detailed Description of the Gasification Technology

The core of the proposed plant is the production of synthesis gas or "syngas." The proposed plant will have six gasifiers feeding two gas processing trains. This arrangement will enable continued syngas supply and operation of the plant during periods of maintenance and other outages of an individual gasifiers or a gas processing train.

The gasifiers will use the General Electric oxygen-blown, quench process. This process includes coal slurry and oxygen feed systems, gasifier reaction chambers, and syngas cooling. The coal feedstock is fed to the gasifiers through an injector that mixes the coal slurry and oxygen for good dispersion in the gasifier. The gasifiers operate in an oxygen deficient mode to prevent combustion of coal and facilitate the physical processes and chemical reactions that produce the syngas.

The gasifiers are designed to operate at high pressure and temperatures (nominally 1,000 psig and 2500°F). The syngas is principally hydrogen and carbon monoxide. The gasifiers also generate two byproducts from the coal, a coarse vitreous slag, which comes out the bottom of the gasifiers, and a fine slag, which is entrained in and carried out with the syngas.

Prior to leaving the gasifier, syngas contacts a water pool (quench section) located at the bottom of the unit which enhances collection of the slag.

The raw syngas from the gasifiers is composed mainly of hydrogen (H_2), carbon monoxide (CO), water vapor (H_2O) and carbon dioxide (CO_2). The syngas also contains lesser amounts of several components such as hydrogen sulfide (H_2S), carbonyl sulfide (COS), methane (CH_4), and nitrogen (N_2). It also contains entrained fine slag that would be emitted as particulate matter if the raw gas were burned. Because of undesirable components, notably H_2S, COS, and fine slag, the raw syngas produced by the gasifiers must undergo cleanup prior to use in the superheaters or converted to methane in the methanation units. Removal of these components is performed using several gas cleaning techniques.

Fine slag is comprised of unreactive mineral compounds and particles that are not completely gasified, which are mainly un-reactable minerals plus small amounts of unburned carbon. This material is carried from the gasifier with the raw syngas and must be removed prior to entering the gas processing train. The syngas is scrubbed with water to remove the fine slag. It is during this scrubbing step that the hydrogen chloride (HCl), which is formed from the chlorine contained in the coal, is removed. The dirty scrubbing water is flashed to lower pressure and concentrated in the fine slag handling section to recover solids. These solids are then recycled to the coal grinding and feed system.

Most of the slag does not exit with the syngas. It melts in the high temperatures of the gasifier and flows to a quench chamber at the bottom of the gasifier, where the molten slag is quenched with water. The quenched slag is removed from the gasifier through a lock-hopper. The wet slag is then transported to the slag operation to be dewatered. The final slag is a stable glassy frit with very small amounts of residual carbon.

The cooled syngas passes through a carbon bed which removes the mercury as well as other trace pollutants from the coal. After passing through the carbon bed, the syngas is transferred to the Acid Gas Removal (AGR) Units.

The cooled syngas from the mercury removal system still contains high levels of H_2S, COS, and other sulfur compounds which must be removed prior to being sent to the methanation unit. The syngas is sent to the AGR Units to remove the H_2S, COS, and other compounds. The Rectisol™ process uses cold methanol as a solvent in the process. Acid gas partial pressure separation is the key driving force for the Rectisol™ process. Syngas enters the Rectisol™ plant and is cooled with water condensate being removed. The gas then flows to an absorption tower where it is introduced to the Rectisol™ solvent in countercurrent flow. Acid gases in the feed gas are absorbed into the solvent, and a clean feed gas is withdrawn from the top of the absorber column. Acid gas rich solvent from the absorber is regenerated by flashing the gas at medium pressure and then reheating the gas to the solvent boiling point and stripping the solvent.

The Rectisol acid gas removal process will selectively remove sulfur compounds (H_2S and COS) and CO_2. These sulfur compounds will be concentrated in a relatively small stream with CO_2 that will be used to produce sulfuric acid. The CO_2 separated from the syngas in the Rectisol unit will contain over 95 percent CO_2 with low concentrations of methanol, H_2S, and COS. This CO_2 will be sent to an RTO to further reduce emissions of CO and hazardous air pollutants (i.e., methanol).

All relief streams discharging syngas will be collected from safety valve discharges, process vents, etc., and exhausted to the atmosphere by means of two flares from each gas cleanup train. Acid gas relief streams will be collected from safety valve discharges, process vents, etc., and safely exhausted to the atmosphere by means of two additional flares. The gas streams to be flared will be routed via a header and a knockout drum to the flare. The flares will receive scrubbed syngas during gasifier startups and shutdowns. There will be a total of four flares at the plant.

Flares will be equipped with natural gas fired pilot burners to ignite process gas sent to the flare and initiated combustion. Actual flaring will be of brief durations during startup and upsets of units in the gasification block. Nitrogen purging will also be used to minimize emissions.

Oxygen for the gasifiers is produced at the plant in an Air Separation Unit (ASU). The ASUs use cold refrigeration to separate ambient air into oxygen (O_2) and nitrogen (N_2). The oxygen stream is in excess of 95% purity (95% O_2 and 5% N_2), as required for efficient production of syngas in the gasifiers. The nitrogen will be used at the plant, e.g., for purging process vessels, with the remainder available for sale as another by-product from the plant.

Attachment 2 – Summary of Proposed BACT Determination

Gasification Block:

Pollutant	Principal Control Measures	Limit
Acid Gas Removal Units		
SO_2	Removal of TRS w/Rectisol process (acid gas stream to sulfuric acid plants)	Work Practice
CO	Oxidizers	10 ppm
Flares (startup, shutdown and malfunction)		
CO & SO_2	Good combustion practices and flaring minimization planning	Work Practice and Secondary Emission Limit

Sulfuric Acid Plant:

Pollutant	Principal Control Measures	Limit
NO_x	SCR	0.16 lb/ton of acid
CO	Good combustion practices	0.32 lb/ton of acid
PM	Good combustion practices	0.01 lb/ton of acid
SO_2	Peroxide scrubber	1.41 lb/ton of acid
H_2SO_4		0.06 lb/ton of acid

Superheaters:

Pollutant	Control Measures	Limitation
PM	Good combustion practices	0.010 lb/mmBtu
NO_x	Selective catalytic reduction	0.035 lb/mmBtu
SO_2	Low sulfur fuel	0.0013 lb/mmBtu
CO	Good combustion practices	0.040 lb/mmBtu

Auxiliary Boiler:

Pollutant	Control Measures	Limitation
PM	Good combustion practices/use of natural gas	0.010 lb/mmBtu
NO_x	Low-NO_x burners and flue gas recirculation	0.035 lb/mmBtu
SO_2	Low sulfur fuel	0.0013 lb/mmBtu
CO	Good combustion practices	0.040 lb/mmBtu

Material Handling Operations (Particulate Matter):

Emission Unit	Control Measures	Limitation
Coal Receiving and Storage	Enclosure and baghouses	0.001 gr/dscf

Other Operations (Particulate Matter):

Emission Unit	Control Measures	Limitation
Cooling Tower	Drift Eliminator Design	0.0005% Drift
Plant Roadways and Open Areas	Paving and Dust control program	N/A