Illinois Environmental Protection Agency
Bureau of Air, Permit Section
1021 North Grand Avenue East
P.O. Box 19276
Springfield, Illinois 62794-9276

Project Summary for a Construction Permit Application from Christian County Generation, LLC for the Taylorville Energy Center Christian County, Illinois

Site Identification No.: 021060ACB
Application No.: 05040027
Date Received:

Schedule:

Public Comment Period Begins: October 17, 2011
Public Hearing: December 1, 2011
Public Comment Period Closes: December 31, 2011

Illinois EPA Contacts:

Permit Analyst: Robert Smet
Community Relations Coordinator: Brad Frost

I. INTRODUCTION

Christian County Generation, LLC, has submitted an application for a permit to construct the Taylorville Energy Center.[1] This plant would use coal gasification technology to produce substitute natural gas (SNG) for sale or use on-site to generate electricity. This plant would be located approximately two miles northeast of the City of Taylorville.

Christian County Generation must obtain an air pollution control construction permit from the Illinois EPA for the proposed plant because it would be a source of emissions. The Illinois EPA has reviewed Christian County Generation's permit application and made a preliminary determination that it meets applicable requirements. Accordingly, the Illinois EPA has prepared a draft of the construction permit that it would propose to issue for the plant.[2] However, before issuing this permit, the Illinois EPA is holding a public comment period with a hearing to receive written and oral comments on the proposed issuance of a construction permit for the plant and the terms and conditions of the draft permit.

Because the proposed plant would generate electricity that goes to the power grid, Christian County Generation must also obtain an Acid Rain permit for the plant. A draft of this permit, which addresses requirements of the federal Acid Rain program, is included as Attachment 3 of the draft construction permit.

II. PROJECT DESCRIPTION

The proposed plant would make substitute natural gas (SNG) from coal using gasification technology. SNG is composed of methane, the principal component of commercial natural gas, and is interchangeable with pipeline natural gas. The design feedstock for the plant would be Illinois Basin coal. The gasification section of the plant or "gasification block" would have a nominal capacity of about 64 million cubic feet of SNG per day. The SNG would either be sold as a product and leave the plant by pipeline and/or be used on-site in the plant's "power block" to generate electricity.

The power block at the plant would have two combined cycle combustion turbines and a single shared steam turbine.[3] Heat energy from the gasification block,

---

[1] General references to the permit application in this project summary refer to the three volume "Updated Prevention of Significant Deterioration and State Construction Permit Application for the Taylorville Energy Center" submitted by Christian County Generation in the following three parts: 1) Volume 1 of 3 - Updated Permit Application submitted on September 24, 2010, 2) Volume 2 of 3 – Class II Area Air Quality Modeling Report submitted on October 14, 2010, and 3) Volume 3 of 3 – Greenhouse Gas Best Available Control Technology Analysis submitted October 27, 2010. In this project summary, these application submittals are generally referred to as "the Application."

[2] The Illinois EPA previously issued a construction permit for the Taylorville Energy Center. That permit, issued in January 2008, addressed a plant that would have only generated electricity from coal and would not have produced SNG. Christian County Generation has changed its plans for the plant to include production of SNG, preparing an updated permit application for the plant that was initially received by the Illinois EPA on April 8, 2010 and later updated as indicated above. The draft permit that the Illinois EPA has now prepared addresses the new plans for the plant with production of both SNG and electricity from SNG.

[3] In a combined cycle turbine, electricity is produced both by a generator driven by the combustion turbine and by a separate generator powered by a steam turbine. The steam turbine is supplied with steam produced from the hot exhaust of the combustion turbine

recovered as steam, would also contribute to the electrical output of the power block. The nominal net output to the grid from the plant is expected to be about 630 Megawatts (MW) after accounting for electricity used in the gasification block and other operations at the plant. In addition to firing SNG, the combustion turbines in the power block would also be able to fire commercial, pipeline natural gas, so they could operate independently of the gasification block. The power block would be developed so that one of the combustion turbines would generate base load power, potentially running at or near capacity for months at a time with only minor downtime.

Coal gasification uses high temperature reactors or gasifiers to convert coal into a synthesis gas (syngas), which is composed mainly of hydrogen, carbon monoxide and carbon dioxide. After being processed in a cleanup train to remove contaminants, the cleaned or sweet syngas can be used as fuel or further processed into a desired product, such as SNG.[4]

The gasification block at the proposed plant would have two identical gasifiers. A single cleanup train would process the raw syngas from both gasifiers to remove entrained particulate by water-wash, sulfur compounds and carbon dioxide (CO_2) with an acid gas recovery unit (AGR Unit), and mercury with activated carbon beds. To make SNG, a Methanation Unit would convert the sweet syngas into methane. There would also be a reactor between the particulate removal and AGR Unit in the cleanup train to adjust or shift the ratio of carbon monoxide and hydrogen in the syngas for production of methane.

---

using a waste heat boiler or "heat recovery steam generator" (HRSG). At the proposed plant, a single steam turbine generator would be powered by steam recovered from the exhaust of the two combustion turbines in the power block and by steam recovered from various heat exchangers in the gasification block.

[4] The emission levels that are achievable with gasification technology for different pollutants are generally significantly lower than those achieved with combustion or boiler-based power generation technology. This is because the contaminants present in the coal [e.g., particulate (ash), chlorides, and sulfur] are removed from fuel prior to combustion, rather than after combustion when these contaminants would be present at much lower concentrations. Accordingly, coal gasification, as recognized by USEPA, USDOE, and other experts, is expected to be at the heart of future generations of clean coal power plants, as gasification offers one of the cleanest and most versatile means to convert coal into electricity, as well as into SNG and other products. As the proposed plant would be developed with gasification technology, this also provides an additional basis to support the overall project from a broad environmental perspective, as the plant would facilitate the continued development and commercial application of coal gasification technology to meet the nation's energy needs.

However, unlike IGCC facilities, which fire syngas in the combustion turbines and for which the syngas cleanup train serves as both process equipment and emission control equipment for the turbines, the cleanup train at the proposed plant would be process equipment for the production of SNG. Without effective particulate and sulfur removal by the cleanup train, the clean syngas fed to the Methanation Unit would not have the quality needed to prevent poisoning and plugging of the catalyst beds in this unit. In this regard, the particulate and sulfur removal equipment in the syngas cleanup train at the proposed plant is not selected as an emission control technology for the purpose of reducing emissions from any of the emission units that combust either sweet syngas or SNG such as the combustion turbines, auxiliary boiler, and AGR Unit oxidizer. Moreover, the level of particulate and sulfur removal needed to protect the catalyst in the Methanation Unit is likely more stringent than would otherwise be required for either syngas or SNG to be fired in these gas-fired units. The equipment in the syngas cleanup train does, however, affect the composition of the off-specification raw and sour syngas that would be vented to the flare during startup, shutdown, and malfunction events. As such, the draft permit requires use of the syngas cleanup train, including the Rectisol® AGR Unit as an inherent design element for the plant that may influence the nature of emissions due to flaring.

The sulfur compounds removed from raw syngas by the AGR Unit, which are present mainly as hydrogen sulfide, would be further processed in a sulfur recovery unit (SR Unit). The SR Unit would convert the concentrated stream of sulfur compounds or acid gas from the AGR Unit into elemental sulfur, which would be a saleable byproduct from the plant. For further description of the gasification process at the proposed plant, see Attachment 3 at the end of this document.

The main point of greenhouse gas emissions during normal operation of the gasification block would be the CO_2 vent on the AGR Unit. This would be the principle source of CO_2 emissions from the gasification process, discharging over 99 percent of the emissions of CO_2 and greenhouse gases from the production of SNG. The carbon monoxide and volatile organic material also present in this stream would be controlled by combustion in a catalytic oxidizer before the stream is discharged to the atmosphere. This oxidizer would also combust residual levels of sulfur compounds in this stream, resulting in emissions of sulfur dioxide.

Christian County Generation expects that at some point after the plant begins operation, this CO_2 stream from the AGR Unit will normally not go to the atmosphere and will instead be geologically sequestered. At such time, this CO_2 stream would only be discharged to the atmosphere during outage of the sequestration facilities and during startup, shutdown and upset of the gasification block, when this stream is not suitable for sequestration. Preferably, sequestration would be accomplished in combination with use of the CO_2 for enhanced oil recovery.[5] Otherwise, CO_2 would likely be sequestered in the Mt. Simon sandstone formation underlying southeastern Illinois. The CO_2 stream would not be sequestered when the plant begins operation since the necessary prerequisites for sequestration would not be present. CO_2 is not currently being used commercially in Illinois for enhanced oil recovery.[6] Other than in limited duration demonstration projects, which are supported by funding from the United States Department of Energy and other governmental agencies, geological formations are not being used for direct sequestration of CO_2, either in Illinois or elsewhere in the United States, in the absence of accompanying enhanced oil recovery. These demonstration projects are needed to develop and refine the technology for sequestration in geological formations and to define and reduce the associated costs. In addition, sequestration is

[5] "Enhanced oil recovery" involves various techniques for extracting additional crude oil from an oil field after pumping and other simpler recovery techniques are no longer effective. When CO_2 or other suitable gas is used for enhanced oil recovery, the gas is injected into the oil deposit for a period of time through the existing wells. In addition to the beneficial effect of the pressure of the gas on the crude oil remaining in the deposit, the gas can also enhance oil recovery as it reduces the viscosity of the oil. The extent of additional recovery with CO_2 injection depends on factors such as reservoir temperature, pressure and the composition of the oil. The physical mechanisms for oil recovery range from oil swelling and viscosity reduction with CO_2 injection at low pressures to completely miscible displacement in high-pressure applications. In these applications, up to two-thirds of the injected CO_2 returns with the recovered oil and is usually recovered for re-injection into the deposit to minimize operating costs. The remainder of the CO_2 is trapped underground in the oil deposit.

[6] Enhanced oil recovery with CO_2 is currently conducted in various oil fields in the United States, although not in Illinois. The oil fields nearest the plant site in which CO_2 is currently being used for oil recovery are in southern Mississippi. Use of CO_2 from the proposed plant for enhanced oil recovery in those fields would require construction of a pipeline that would be about 400 miles in length, to connect to the existing CO_2 pipeline serving those fields. The utility of and favorable economics for such a pipeline cannot be assumed with the construction of the proposed plant.

impeded by the lack of a national program for control of CO_2, which would provide economic support for sequestration.[7]

During normal operation of the gasification block, there would also be emissions from the oxidizer scrubber system on the SR Unit. These emissions would not be due to this unit itself, since the exhaust or tailgas from this unit would be routed back to the inlet of the AGR Unit. However, low volume exhaust streams from other operations in the gasification block, such as liquid sulfur storage, would also be routed to this oxidizer-scrubber. These streams would be combusted in the oxidizer, converting hydrogen sulfide to sulfur dioxide. The scrubber would then control the sulfur dioxide in the stream before discharge to the atmosphere. During startup of the gasification block following a complete shutdown, sour gas from the AGR Unit and tailgas from the SR Unit would also be ducted to the oxidizer-scrubber on the SR Unit.

The flare at the gasification block would also be a source of emissions. The flare would be used to safely dispose of process gas streams during startup, shutdown, and upset of the gasification block, when off-specification process gas streams could not be fed forward for further processing or use. During normal operation of the gasification block, the flare would have emissions from only its pilot burners, which are needed to keep it in readiness for an upset event in which waste gases would go to the flare. These pilot burner emissions would be minimized by firing natural gas. When waste gas streams are flared, the flare would control carbon monoxide, hydrogen sulfide and volatile organic material in the streams. Emissions from flaring would be minimized by the design of the flare and work practices to minimize the occurrence of events that would necessitate such flaring and the amount of gas that is flared during such events.

In the power block, emissions of nitrogen oxides, carbon monoxide and volatile organic matter from the two combustion turbines would be controlled by low-NO_X combustion technology, add-on selective catalytic reduction systems and good combustion practices. Emissions of greenhouse gases would be minimized by the design of the turbines and the power block for efficient use of fuel to generate electricity. Emissions of other pollutants from the turbines would be controlled or minimized by removal of contaminants from the raw syngas in the cleanup train prior to conversion to SNG.

Other emission units at the proposed plant would include storage, processing and handling equipment for coal, slag and other bulk materials, a cooling tower, a natural gas-fired auxiliary boiler, roadways, engines for emergency power, and other ancillary equipment and operations. Emissions would be controlled, as appropriate by design of equipment, work practices and add-on control equipment

III. PROJECT EMISSIONS

[7] Sequestration of the CO_2 from the proposed plant would have been addressed by the Illinois' Clean Coal Portfolio Standard Law (20 ILCS 3855/1-75, as amended by P.A. 95-1027, effective June 1, 2009) as discussed in the updated application. However, the proposed plant is currently not subject to the Clean Coal Portfolio Standard Law. Christian County Generation is still developing the project to satisfy this law's requirements. In particular, those design aspects of the plant that were selected based on the Clean Coal Portfolio Standard Law have not been changed. Accordingly, the current plans for the plant would mean that the plant would still qualify as a "clean coal facility" as would have been defined by this law or could be defined or authorized under future Illinois law.

The potential emissions of the plant are listed below. Actual emissions will be less to the extent that the plant does not operate at its maximum capacity and control equipment and control measures normally operate with a margin of compliance.

Pollutant	Potential Emission (Tons Per Year)
Carbon Monoxide (CO)	1,249
Sulfur Dioxide (SO_2)	697
Nitrogen Oxides (NO_X)	228
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	239/156/111
Volatile Organic Material (VOM)	90.2
Hydrogen Sulfide (H_2S)	8.78
Sulfuric Acid Mist	5.18
Lead, as elemental lead	0.219
Fluorides, as hydrogen fluoride	0.209
Mercury	0.103
Individual HAP (formaldehyde)	5.07
Total HAPs	19.2

The potential emissions of carbon dioxide (CO_2) from the plant would be approximately 4,990,000 tons per year. In addition to CO_2, methane, nitrous oxide (N_2O)[8] and sulfur hexafluoride (SF_6) are also regulated as greenhouse gases. Emissions of these pollutants are expressed in terms of CO_2e by multiplying the emissions of the pollutant by the applicable value for global warming potential or CO_2 equivalents established by USEPA. For example, a ton of methane is considered equivalent to 21 tons of CO_2. The potential emissions of greenhouse gases from the plant including emissions of greenhouse gases other than CO_2, expressed as carbon dioxide equivalents (CO_2e), would be approximately 5,030,000 tons per year.

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. Given the planned air pollution control equipment and control measures, the various emission units in the proposed plant should readily comply with applicable state standards.

Many emission units at the proposed plant would also be subject to federal New Source Performance Standards (NSPS), at 40 CFR Part 60. In particular, the combustion turbines will be subject to requirements of the NSPS for gas turbines (40 CFR 60 Subpart KKKK). Various coal handling operations at the plant will be subject to NSPS for coal preparation plants (40 CFR 60 Subpart Y). The auxiliary boiler will be subject to the NSPS for steam generating units (40 CFR 60 Subpart Db). The methanation unit heater will be subject to the NSPS for small steam generating units (40 CFR 60 Subpart Dc). Emergency engines will

[8] While nitrous oxide (N_2O) is an oxide of nitrogen, it is not a component of the regulated pollutant "nitrogen oxides." In the atmosphere, N_2O is much more stable than the oxides of nitrogen that are regulated as nitrogen oxides, notably nitric oxide (NO) and nitrogen dioxide (NO_2). Because of its stability, N_2O has not been regulated as a precursor to the formation of ozone, particulate matter or NO_2 in the atmosphere.

be subject to the NSPS for stationary compression ignition engines (40 CFR 60 Subpart IIII). Lastly, the methanol storage tank will be subject to the NSPS for volatile organic liquid storage tanks (40 CFR 60, Subpart Kb).

The emergency engines at the plant will also be subject to the requirements of the federal National Emission Standards for Hazardous Air Pollutants (NESHAP), at 40 CFR Part 63, that apply to engines at sources that are not major sources for emissions of hazardous air pollutants (40 CFR 63 Subpart ZZZZ).

V. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The proposed plant is a new major source for purposes of the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. The plant is major for emissions of CO, SO_2, NO_X, PM, PM_{10}, and $PM_{2.5}$ with potential emissions of more than 100 tons per year for each of these pollutants. The proposed plant is also a major source for greenhouse gases (GHG) with potential emissions of more than 100,000 tons per year of GHG as carbon dioxide equivalents (CO_2e). The plant is also subject to PSD for VOM since its potential VOM emissions, 90.2 tons per year, are more than 40 tons per year, the PSD significant emission rate for VOM.[9]

A. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Under the PSD rules, an applicant for a PSD permit must demonstrate that Best Available Control Technology (BACT) will be used to control emissions of pollutants subject to PSD. Christian County Generation has provided a BACT demonstration in the Application addressing emissions of pollutants from the proposed plant that are subject to PSD. A detailed discussion of the proposed BACT determination for various emission units at the proposed plant is provided in Attachment 1 of this document. A summary of the proposed BACT determination is provided in Attachment 2.

By way of general background, 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. This approach is generally followed by the Illinois

[9] Under the PSD rules, a proposed new source that is major for any regulated pollutant is also generally subject to PSD for other pollutants whose potential emissions are above the significant emissions rates specified in the PSD rules, 40 CFR 52.21(b)(23).

EPA for BACT determinations. An important resource for BACT determinations is USEPA's ***RACT/BACT/LAER Clearinghouse*** (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 demonstration of BACT for units at the source subject to PSD was provided in the Application and the proposed determinations of BACT by the Illinois EPA are discussed in Attachment 1. The draft permit includes proposed BACT limits for emissions of pollutants that are subject to PSD, including greenhouse gases. The proposed limits have generally been determined by the Illinois EPA based on the following:

- The information provided by Christian County Generation in the Application;
- The demonstrated ability of similar equipment to meet the proposed emission limits or control requirements;
- Compliance periods associated with limits that are consistent with those used by USEPA in recent revisions to NSPS and NESHAP regulations for new emission units at similar affected facilities;
- Emission limits that account for normal operational variability based on the equipment and control equipment design, when properly operated and maintained; and
- Review of emission limits set for other coal gasification plants, as identified in USEPA's ***RACT/BACT/LAER Clearinghouse***, PSD permits, and permit applications for these similar facilities.

B. Air Quality Analyses And Other Impact Analyses

The PSD rules also require that analyses of the potential air quality impacts and certain other potential impacts of the proposed plant be conducted for the proposed plant. These analyses and their results are discussed in Section VI below.

VI. AIR QUALITY AND OTHER IMPACT ANALYSES

A. Introduction to Air Quality Analysis

Emission standards and limits address the quantity or rate of pollutants emitted by a source, as they are released to the atmosphere from various emission units at a source. 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 that people breathe 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, mobile sources such as cars and trucks, and "background" pollutant levels. The level of 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 in micrograms per cubic meter, millionths of a gram of a pollutant in one cubic meter of air.

The USEPA 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. In an attainment area, like Christian County, 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 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 and CO

An ambient air quality analysis was conducted by a consulting firm, Trinity Consultants, on behalf of Christian County Generation to assess the impacts of the proposed plant on ambient air quality for NO_2, SO_2, PM and CO. 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 results of this analysis are summarized in Tables 1 through 3.

The starting point for determining the extent of the modeling necessary for the proposed plant was evaluating whether it 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. For pollutants for which impacts were above the significant impact level, modeling was done incorporating proposed new emissions units at the proposed plant and significant stationary sources in the surrounding area.

Table 1: Preliminary Impact Analysis
(Significant Impact Assessment)

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
NO_2	1-Hour[b]	149	7.5
	Annual[a]	0.56	1
SO_2	1-Hour[b]	354	7.8
	3-Hour[a]	223	25
	24-Hour[a]	40.2	5
	Annual[a]	1.32	1
PM_{10}	24-Hour[a]	31.2	5
	Annual[a]	4.80	1
$PM_{2.5}$	24-Hour[b]	4.75	1.2
	Annual[b]	0.77	0.3
CO	1-Hour[a]	3,129	2,000
	8-Hour[a]	736	500

Notes:

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

b. Five-year average of the 1st high value based upon evaluation of a 5-year meteorological dataset.

The preliminary impact analysis showed maximum concentrations for NO_2 (1-hour average only), SO_2, PM_{10}, $PM_{2.5}$, and CO that are greater than applicable significant impact levels. This triggered further analysis with modeling of both the emissions of the proposed plant and the emissions of existing sources in the area. Background levels of air quality, as determined at ambient monitoring stations operated by the Illinois EPA and Missouri Department of Natural Resources, were also included in the final results for the NAAQS analysis. These full impact analyses yielded modeled concentrations that were in compliance with the applicable PSD increments and the NAAQS, as shown Tables 2 and Table 3, respectively.

Table 2: PSD Increment Consumption Modeling Results

Pollutant	Averaging Period	PSD Increments ($\mu g/m^3$)	Maximum Concentration ($\mu g/m^3$)
SO_2	3-Hour	512	143[a]
	24-Hour	91	33.1[a]

	Annual	20	2.21[b]
PM_{10}	24-Hour	30	74.7[a,c]
	Annual	17	17[b]
$PM_{2.5}$	24-Hour	9	4.84[a]
	Annual	4	0.83[b]

Notes

a. Highest 2nd high value based upon individual evaluation of each year of a five year meteorological dataset.

b. Highest 1st high value based upon individual evaluation of each year of a five year meteorological dataset.

c. The 24-hr PM_{10} increment “cause or contribute” analysis revealed no modeled receptor-events during which the increment was exceeded and the plant’s modeled impacts were above the SIL, so the plant will not cause or contribute to an exceedance of the 24-hr PM_{10} increment. The maximum 2nd high or above 24-hr PM_{10} PSD Increment impact among the five years modeled from the cause or contribute analysis, after excluding the exceedances for which Christian County Generation demonstrated that the plant will not produce an impact above the SIL, is 29.97 µg/m^3 which is less than the 24-hr PM_{10} PSD Increment.

Table 3: NAAQS Modeling Results

Pollutant	Averaging Period	NAAQS (µg/m^3)	Background Concentration (µg/m^3)	Max. Modeled Concentration (µg/m^3)	Total Concentration (µg/m^3)
NO_2	1-Hour[a,f]	188	28.9[i]	256	285
SO_2	1-Hour[b,g]	196	49.8[j]	150	200
	3-Hour[c]	1,300	189.8[j]	144	334
	24-Hour[c]	365	20.9	33.2	54.1
	Annual[d]	80	5.3	9.97	15.3
PM_{10}	24-Hour[c,h]	150	49[k]	137	186
$PM_{2.5}$	24-Hour[e]	35	28.0[l]	5.79	33.8
	Annual[e]	15	11.6[l]	0.82	12.4
CO	1-Hour[c]	40,000	4,914[m]	3,048	7,962
	8-Hour[c]	10,000	1,667[m]	526	2,193

Notes

a. Evaluated five-year average 8th high 1-hour concentrations as a conservative approximation of the five-year average 8th highest daily maximum 1-hour output for comparison against the NAAQS.

b. Evaluated five-year average 4th high 1-hour concentrations as a conservative approximation of the five-year average 4th highest daily maximum 1-hour output for comparison against the NAAQS.

c. Highest 2nd high value based upon individual evaluation of each year of a 5-year meteorological dataset.

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

e. Evaluated five-year average 1st high 24-hour and annual concentrations in accordance with USEPA guidance.

f. The "cause or contribute" analysis for the 1-hr NO_2 NAAQS revealed no modeled receptor-events during which this NAAQS was exceeded and plant's modeled impacts were above the SIL, so the plant will not cause or contribute to an exceedance of this NAAQS. The maximum five-year average 8th high or above daily maximum 1-hr NO_2 NAAQS impact from this cause or contribute analysis after excluding the exceedances for which Christian County Generation has demonstrated the plant will not have an impact above the SIL is 187.6 $\mu g/m^3$ which is below the 1-hr NO_2 NAAQS.

g. The cause or contribute analysis for the 1-hr SO_2 NAAQS revealed no modeled receptor-events during which this NAAQS was exceeded and the plant's modeled impacts were above the SIL, so the plant will not cause or contribute to an exceedance of this NAAQS. The maximum five-year average 4th high or above daily maximum 1-hr SO_2 NAAQS impact from this cause or contribute analysis after excluding the exceedances for which Christian County Generation has demonstrated the plant will not have an impact above the SIL is 194.1 $\mu g/m^3$, which is below the 1-hr SO_2 NAAQS.

h. The cause or contribute analysis for the 24-hr PM_{10} NAAQS revealed no modeled receptor-events during which the NAAQS was exceeded and the plant's modeled impacts were above the SIL, so the plant will not cause or contribute to an exceedance of this NAAQS. The maximum 2nd high or above 24-hr PM_{10} NAAQS impact among the five years modeled from this cause or contribute analysis after excluding the exceedances for which Christian County Generation has demonstrated the plant will not have an impact above the SIL is 149.4 $\mu g/m^3$ which is below the 24-hr PM_{10} NAAQS.

i. Based on NO_2 ambient monitoring data from Bonne Terre, Ste. Genevieve County, Missouri (Site ID 291860005) for the three year period from 2007 to 2009. Background concentration is the three-year average from 2007 to 2009 of the 98th percentile 1-hour daily maximum concentrations.

j. Based on SO_2 ambient monitoring data from Nilwood, Illinois (Site ID 171170002-1). Background concentration for 1-hr modeling is the three-year average from 2007 to 2009 of the 99th percentile 1-hour daily maximum concentrations. Background concentration for the 3-hr and 24-hr modeling are the highest second high value recorded from among the three year period from 2006 to 2008, and the background concentration for the annual modeling is the highest annual average monitor value from 2006 to 2008.

k. Based on PM_{10} ambient monitoring data from Nilwood, Illinois (Site ID 171170002-1) for the three year period from 2006 to 2008. Background concentration for 24-hour average is the fourth high from the three year period, since the 24-hr average PM_{10} NAAQS is not to be exceeded more than three times in three consecutive years.

l. Based on $PM_{2.5}$ ambient monitoring data from the State Fairgrounds site in Springfield, Illinois (Site ID 171670012-1) for the three year period from 2007 to 2009. Background concentration for 24-hr average is the 98th percentile of 24-hr average concentrations in a given year averaged over the three year period from 2007 to 2009. The background concentration for the annual average is annual arithmetic mean averaged over three years.

m. Based on CO ambient monitoring data from the downtown site in Springfield, Illinois (Site ID 171670008) for the three year period from 2006 to 2008. Since the 1-hr and 8-hr CO NAAQS are not to be exceeded more than once per year, the background concentrations were set to the highest second high monitor value from 2006 to 2008.

C. Ozone Ambient Impact Analysis

Elevated ground-level ozone concentrations are the result of photochemical reactions among various pollutants. These reactions are more likely to occur under certain weather conditions (e.g., high temperatures, light winds, and sunny conditions). The pollutants that contribute to ozone formation, referred to as ozone precursors, include NO_X and VOM emissions from both anthropogenic (e.g., mobile and stationary sources) and natural sources (e.g., vegetation). While the proposed plant will not directly emit ozone, it will emit more than 100 tons per year of NO_X. Christian County Generation was, therefore, required to conduct an analysis for ozone as part of the PSD air quality analysis. This analysis addressed potential local and downwind impacts from the plant on air quality for ozone.

Christian County Generation conducted the required ozone analysis by examining local impacts based on a quantitative approach using the Screening Method calculations recommended by Illinois EPA. This method uses conservative screening tables in lieu of source-specific photochemical modeling or other quantitative ozone impact analysis procedures. In addition, evaluating compliance with the previously revoked 1-hr ozone NAAQS (i.e., 0.12 ppm which is not to be exceeded more than 3 times in 3 consecutive years) by adding source-specific 1-hr ozone concentrations predicted using the screening tables to a representative 1-hr ozone background serves as a surrogate for evaluating compliance with the newer 8-hour average NAAQS (i.e., 0.075 ppm evaluated as the 3-year average of annual fourth highest daily maximum 8-hr ozone concentrations).

Christian County Generation first determined the expected 1-hour average ozone impact resulting from the plant using the rural VOC/NOX Point Source Screening Tables and the plant's potential NO_X and VOM emission rates.[10] Based on this screening estimate, the expected 1-hr average ozone impact for the plant is 0.020 ppm. This impact was added to the 1-hr average ozone background concentration of 0.089 ppm (based on the fourth highest 1-hr average concentration monitored at the Nilwood site over the three year period from 2006 to 2008) to provide a cumulative 1-hr average design concentration of 0.109 ppm. The 1-hr average design concentration (0.109 ppm) was determined to be less than the 1-hr average ozone NAAQS (0.12 ppm). Therefore, the plant is not expected to cause or contribute to a violation of the ozone NAAQS.

D. Vegetation and Soils Analysis

An applicant for a PSD permit is required to conduct an analysis of the potential impairment to soils and vegetation that may occur as a result of a proposed major project. Christian County Generation evaluated potential impacts on soils and vegetation from VOM and sulfur, nitrogen, and PM deposition in addition to direct phytotoxic effects of the modeled

[10] Scheffe, Richard, USEPA, ***VOC/NOx Point Source Screening Tables***, September 1988.

pollutants (i.e., CO, NO_X, SO_2 and PM). The complete soils and vegetation analysis provided: 1) the characteristics of the land use, soils, and, vegetation in the impact area, 2) a discussion of the general soil and vegetation sensitivity to CO, NO_X, SO_2, PM, VOM, ozone, and sulfur/nitrogen deposition, 3) the observed thresholds below which adverse effects from these pollutants are expected to be negligible, 4) the dispersion modeling methodologies that were implemented to produce air concentrations and deposition rates for comparison against the selected thresholds, and 5) a summary of the results of the soil and vegetation impact assessment. By first describing the basic matrix of both agricultural and natural plant communities in the impact area, Christian County Generation was able to conduct a more efficient analysis of possible impacts from the plant project’s PSD triggering pollutant emissions. Specifically, during the course of the literature review conducted to establish soils and vegetation screening thresholds for potential adverse impacts, Christian County Generation began by searching the available literature for toxicological studies of the species known to exist within the impact area with a primary focus on the predominant plant species, corn and soybeans.

The screening thresholds established in the soils and vegetation analysis that are expected to be protective of even the most sensitive soils and vegetation in the impact area and are presented in Table 4 below.

In order to assess compliance with the acute screening threshold for direct NO_X exposure [100 ppb (189 μg/m^3) on a 1-hr average basis], Christian County Generation relied on the results of the 1-hr NO_2 NAAQS Analysis. As shown in Table 3, the plant would not cause or contribute to an exceedance of the 1-hr NO_2 NAAQS, which is equivalent to the selected acute screening threshold, and therefore, no adverse impacts to soils and vegetation from direct NO_X exposure attributable to the plant are expected.

Table 4: Ecological Screening Thresholds

Pollutant	Acute Ecological Screening Threshold				Chronic Ecological Screening Threshold			
	Value	Units	Avg.	Ref.	Value	Units	Avg.	Ref.
NO_X	189	μg/m^3	1-hr	a	NA			
SO_2	790	μg/m^3	3-hr	b	20	μg/m^3	Ann.	c
CO	5,000	μg/m^3	8-hr	d	NA			
Species Found in PM								
Sulfur deposition	NA				8	kg/ha/yr	Ann.	c
Nitrogen deposition	NA				7.5	kg/ha/yr	Ann.	c
Chromium	NA				200	μg/kg soil	Ann.	e
	NA				18	μg/kg plant	Ann.	e
Benzo(a)anthracene	NA				18,000	μg/kg soil	Ann.	f
	NA				1,200	μg/kg plant	Ann.	e
Species Found in VOM								
Benzene	NA				255	μg/kg soil	Ann.	e
Ozone	7	ppm-hrs	W126	g	7	ppm-hrs	W126	g, h

Notes

a. USEPA Environmental Criteria Assessment Office, ***Air Quality Criteria for Oxides of Nitrogen***, Volume II, EPA600/8-91/049bF, August 1993.

b. USEPA Environmental Criteria Assessment Office, ***Air Quality Criteria for Particulate Matter and Sulfur Oxides***, Volume III, EPA600/8-82-029c, December 1982.

c. World Health Organization Regional Office for Europe, ***Air Quality Guidelines for Europe***, 2nd Ed., 2000.

d. Directive 2008/50/EC of the European Parliament and of the Council of the European Union: On Ambient Air Quality And Cleaner Air for Europe, May 21, 2008.

e. USEPA Office of Solid Waste and Emergency Response, ***Screening Level Ecological Risk Assessment Protocol for Hazardous Waste Combustion Facilities***, EPA530-D-99-001A, August 1999.

f. USEPA Office of Solid Waste and Emergency Response, ***Waste and Cleanup Risk Assessment, Ecological Soil Screening Level (Eco-SSLs) Guidance and Documents***, April 4, 2005, available at http://www.epa.gov/oswer/riskassessment/ecorisk/ecossl.htm.

g. "W126" is a weighted exposure index for ozone developed by USEPA to address ambient concentrations of ozone as related to impacts on vegetation. It is a cumulative (not average) index to address the biological effect of ozone on vegetation, with higher weightings placed on the higher hourly ozone concentrations.

h. 75 FR 2938, National Ambient Air Quality Standards for Ozone, Proposed Rule, January 19, 2010.

In order to assess compliance with the acute and chronic screening thresholds for direct SO_2 exposure (790 $\mu g/m^3$ on a 3-hr average basis and 20 $\mu g/m^3$ on an annual average basis, respectively), Christian County Generation relied on the results of the 3-hr and annual SO_2 NAAQS Analyses. As shown in Table 3, the 3-hr and annual average impacts from the NAAQS analysis including background are well below the acute and chronic screening thresholds, respectively. Therefore, no adverse impacts to soils and vegetation from direct SO_2 exposure attributable to the plant are expected.

In order to assess compliance with the acute screening threshold for direct CO exposure (5,000 $\mu g/m^3$ on an 8-hr average basis), Christian County Generation relied on the results of the 8-hr CO NAAQS Analysis. As shown in Table 3, the 8-hr average impacts from the NAAQS analysis including background are well less than the acute screening threshold, and therefore, no adverse impacts to soils and vegetation from direct CO exposure attributable to the plant are expected.

Sulfur and nitrogen deposition includes both wet and dry deposition of gases (primarily SO_2 and NO_X) and particles (primarily sulfates and nitrates). Therefore, Christian County Generation evaluated total sulfur and nitrogen deposition for the project based on the sum of gaseous and particulate sulfur and nitrogen deposition. The maximum total gas and particle sulfur and nitrogen deposition rates calculated based on the model output were summed (independent of receptor location) to calculate the total sulfur and nitrogen deposition rates for comparison against the screening thresholds. As shown in Table 5 below, the maximum total nitrogen deposition rate for the project added to background is less than the chronic screening threshold, and therefore, no adverse impacts from nitrogen deposition attributable to the plant are expected.

Although the maximum sulfur deposition rate from the plant plus background is slightly greater than the chronic screening threshold (i.e., less than 1 percent above the screening threshold) on a worst-case basis, the plant's maximum sulfur deposition rate is 5 percent of the chronic screening threshold, and therefore, the plant's contribution to cumulative sulfur deposition rates is insignificant. In addition, the selected chronic screening threshold was conservatively based on the low end of the applicable critical load range identified in the literature (8-16 kg/ha/yr), and as such, it does not fully account for the high average pH, high cation exchange capacity and high base saturation percentage for the soils in the area surrounding the plant. Therefore, this threshold does not necessarily reflect an adverse impact level for the predominantly agricultural soils in the area located at or very near the plant with predicted impacts above the screening threshold. For these reasons, no adverse impacts from sulfur deposition attributable to the plant are expected despite the limited number of modeled impacts greater than chronic screening threshold.

Table 5: Annual Nitrogen and Sulfur Deposition Analysis Results

Pollutant	Chronic Ecological Screening Threshold (kg/ha/yr)	Max. Modeled Deposition ($g/m^2/yr$)	Max. Modeled Deposition (kg/ha/yr)	Background Dep.[a] (kg/ha/yr)	Total Dep. (kg/ha/yr)
Nitrogen Deposition					
Gaseous	----	0.037	0.11	----	----
Particulate	----	0.0010	0.0021	----	----
Total	7.5	0.038	0.12	6.83	6.95
Sulfur Deposition					
Gaseous	----	0.073	0.37	----	----
Particulate	----	0.0025	0.0082	----	----
Total	8	0.076	0.38	7.69	8.07

Notes

a. Based on monitoring data from the Bondville, Illinois, National Atmospheric Deposition Program (NADP) monitoring location (NADP Site ID IL11 and CASTNET Site ID BVL130).

Christian County Generation conducted particle-phase deposition modeling for chromium to determine the maximum offsite annual average deposition rate and used the maximum deposition rate from among the five-years modeled to calculate the maximum accumulated soil and plant tissue concentrations at the end of the plant's useful life, consistent with the procedure outlined in Section 3.11.1 of the Screening Level Ecological Risk Assessment Protocol (SLERAP). The results of these calculations based on the deposition modeling results show the proposed plant's impacts on soil and plant tissue from chromium emissions are negligible (i.e., approximately 1 percent of the chronic screening thresholds or 2.13 µg Cr/kg versus a screening threshold of 200 µg Cr/kg for soil and 0.081 µg/kg versus a screening threshold of 18 µg/kg for plant tissue).

Christian County Generation conducted gaseous and particle bound deposition modeling for benzo(a)anthracene to determine the maximum offsite annual average air concentration and deposition rates and used these results to calculate the maximum accumulated soil and plant tissue concentrations at the end of the proposed plant's useful life, consistent with Section 3.11.1 of the SLERAP. The results of these calculations based on the air concentration and deposition modeling results presented show the proposed plant is not expected to cause an adverse impact on soils and plants from benzo(a)anthracene emissions (i.e., soil concentration is negligible, 0.00028 µg/kg versus a screening threshold of 18,000 µg/kg, and plant tissue concentration is less than 50 percent of the chronic screening threshold, 561 µg/kg versus 1,200 µg/kg).

Christian County Generation conducted gas-phase deposition modeling for benzene to determine the maximum offsite annual average deposition rate and used these results to calculate the maximum accumulated soil concentration at the end of the plant's useful life, consistent with the procedure outlined in Section 3.11.1 of the SLERAP. The results of the benzene soil concentration calculations based on the deposition modeling results show the plant's soil impacts from benzene emissions are negligible (i.e., less than 0.25 percent of the chronic screening threshold, 0.58 µg/kg soil versus a screening threshold of 255 µg/kg soil).

Finally, based on the potential annual emissions of ozone precursors from the proposed plant, Christian County Generation has estimated that any increases in ambient ozone resulting from the plant will be minimal [less than 0.0003 ppm or 0.3 ppb, 8-hour average basis] and that this very small increase will not cause any adverse impacts to soils and vegetation in the area around the plant. The ozone source apportionment modeling prepared by the Illinois EPA for the St. Louis 8-hour ozone attainment SIP shows that total anthropogenic NO_X and VOM emissions from the St. Louis area contributed to approximately 34 ppb of ozone formation for the worst-case episode modeled.[11] This increase in ambient ozone concentration corresponded to an ozone formation potential from anthropogenic sources of 0.065 ppb/tpd for NO_X and 0.11 ppb/tpd for VOM based on the modeled NO_X and VOM emissions (526 and 320 tpd, respectively). Christian County Generation evaluated the potential increase in ozone formation attributable to the plant based on these ppb/tpd ozone formation potentials for the St. Louis area and the maximum daily NO_X and VOM emissions for the plant. In order to determine whether this level of increased ozone in the area around the plant poses a potential adverse impact to soils and vegetation, Christian County Generation calculated the three-year average (2006 to 2008) of this highest three-month W126 statistic within the ozone season assuming the ozone concentration increase from the plant occurred for every hour of the year. The resulting W126 statistic in the form of the proposed secondary NAAQS is 0.0000775 ppm-hrs which represents a negligible fraction of the proposed chronic screening threshold of 7 ppm-hrs. A reasonable estimate for a "de minimis impact level" for ozone can be developed based on 4 percent of the NAAQS consistent with the recent interim 1-hr NO_2 SIL proposed by USEPA, and therefore, Christian County Generation used 0.28 ppm-hours as a "SIL" for the direct ozone exposure portion of the soils and vegetation analysis to determine that the plant would not cause any adverse impacts.

E. Construction and Growth Analysis

[11] Refer to Table 6-5 and Figure 6-8 in the technical support document prepared by the Illinois EPA, ***St. Louis 8-hour Ozone Technical Support Document***, March 26, 2007.

Christian County Generation provided a discussion of the emissions impacts resulting from residential and commercial growth associated with construction of the proposed plant. 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 work force and is supported by the existing infrastructure, impacts would be minimal and distributed throughout the region.

F. Class II Area Visibility Analysis

The remainder of the additional impacts analysis addresses impacts on visibility at potentially sensitive Class II areas resulting from coherent plumes emanating from the proposed plant. To demonstrate that local visibility impairment does not result from the proposed plant, Christian County Generation has utilized the USEPA VISCREEN model following the guidelines published in the ***Workbook for Plume Visual Impact Screening and Analysis*** to assess potential plume impairment.[12] The VISCREEN model is designed to determine whether a plume from a facility may be visible from a given vantage point. Christian County Generation chose and Illinois EPA approved the approach of addressing visibility impairment at Sanchris Lake State Park, the closest state park to the proposed plant (i.e., the closest location with a potentially sensitive scenic vista). Since potential NO_X and PM_{10} emissions from the proposed project trigger PSD review, all VISCREEN visibility affecting pollutants emitted by the plant were considered in the analysis [i.e., particulates (as PM_{10}), NO_X (as NO_2), and primary SO_4 (as H_2SO_4)].

Level-1 screening techniques using worst-case meteorology were not adequate to demonstrate plume impairment values below screening thresholds for the location considered in this analysis; therefore, a Level-2 screening analysis was completed. For the Level-2 analysis, the worst case meteorological conditions were determined by creating a joint frequency distribution of atmospheric stability and wind speeds for the meteorological dataset selected for the project. This analysis indicated the combination of atmospheric stability and wind speed conditions most likely to occur that would potentially cause visible plume impairment. No other alterations to the default conservative assumptions were made in the model runs. Using these data, no adverse impacts on visibility from plume blight were demonstrated at the selected sensitive receptors.

G. Class I Area Air Quality Related Value Analysis

Class I areas are federally protected areas for which more stringent PSD increments apply to protect natural, cultural, recreational, and/or historic values. The closest Class I area to the proposed plant, and the only such area within 300 km, is the Mingo Wilderness Area, located approximately 293 km south-southwest from the plant site. The Federal Land Manager (FLM) for this Class I area is the US Fish and Wildlife Service (USFWS), who is

---

[12] USEPA, ***Workbook for Plume Visual Impact Screening and Analysis***, EPA-450/4-88-015, 1988.

responsible for protecting air quality related values (AQRVs) and recommends to the permitting authority whether a proposed major emitting facility will potentially have adverse impact on AQRVs, for which PSD modeling may be conducted include visibility and deposition of sulfur and nitrogen. In addition, a Class I area modeling analysis may include an evaluation of Class I PSD Increment consumption.

Due to the distance from the nearest Class I area and the magnitude and characteristics of the plant's emissions, the FLM and USEPA Region 5 in consultation with Illinois EPA agreed that a Class I area modeling analysis is not warranted for this project.[13]

VII. OTHER APPLICABLE REGULATORY REQUIREMENTS

A. Maximum Achievable Control Technology (MACT)

The potential emissions of the proposed plant for hazardous air pollutants (HAPs) are less than 25 tons per year in the aggregate and less than 10 tons per year for any single HAP, so the plant is not a major source for HAPs. Accordingly, a case-by-case determination of Maximum Achievable Control technology (MACT) pursuant to Section 112(g) of the Clean Air Act is not needed for emission units at the plant that would not be subject to NESHAP standards adopted by USEPA.

B. Federal Acid Rain Program

The proposed plant is an affected source and the two combustion turbines are affected units for purposes of the federal Acid Rain Program under Title IV of the Clean Air Act. The Acid Rain program establishes requirements for affected sources related to control of emissions of SO_2 and NO_X, pollutants that contribute to acid rain. Under the Acid Rain program, Christian County Generation would have to hold and surrender SO_2 allowances for the actual SO_2 emissions of the two combustion turbines. Another requirement of the Acid Rain program is to operate pursuant to an Acid Rain permit. The Illinois EPA is proposing to issue the initial Acid Rain permit for the proposed plant in conjunction with issuance of the construction permit for the plant. (See Attachment 3 of the draft permit.)

C. Cross-State Air Pollution Rules (CSAPR)

The two combustion turbines will be subject to the requirements of USEPA's new Cross-State Air Pollution Rules (CSAPR), which will replace state requirements at 35 IAC Part 225, Illinois' version of USEPA's Clean Air Interstate Rule.

D. Clean Air Act Permit Program (CAAPP)

The proposed plant would be a major source under Illinois' Clean Air Act Permit Program (CAAPP) pursuant to Title V of the Clean Air Act. Christian County Generation would have to apply for its CAAPP operating permit within 12 months after initial startup of the plant.

[13] Email from Meredith Bond, United Stated Fish and Wildlife Service, to Larry Carlson, Tenaska, entitled "Taylorville Energy Center Class I Consultation," May 24, 2010.

VIII. DRAFT PERMIT

The Illinois EPA has prepared a draft of the construction permit that it would propose to issue for the proposed plant. The conditions of the permit would set forth the emission control requirements that apply to the various units at the plant. This would include the permitted emissions of the plant. It would also include the applicable emission standards, and the requirements and limits that must be met as BACT for emissions of pollutants that are subject to PSD. Finally, it would include the control measures that must be used and the limits that must be met for emissions of other regulated pollutants.

Limits are set for each pollutant for which the plant is major under the PSD rules, and for some pollutants for which the plant is not major. In addition to annual limits on emissions, the permit includes short-term emission limits and operational requirements, as needed, to provide practical enforceability of the annual emission limits. 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 limits.

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 limits and requirements established for individual emission units.

IX. REQUEST FOR COMMENTS

It is the Illinois EPA's preliminary determination that the draft permit would meet all applicable state and federal air pollution control requirements, subject to the conditions in the draft permit.

Attachment 1 – Discussion of Proposed BACT Determination

Part 1: Overview of Plant Design and Selected Design Feedstock

A. General Discussion of the Plant Design And Selected Feedstock

Christian County Generation has proposed to construct a plant with the objective of producing two commodities, SNG and electricity, and developing a plant that would qualify as a Clean Coal Facility under the Clean Coal Portfolio Standard Law. Location of this plant near (1) ample supplies of suitable coal and adequate water, (2) markets for these commodities, and (3) the necessary product transportation infrastructure, i.e., natural gas pipelines and electrical transmission lines, is critical. Location in an area served by natural gas pipelines also means that the plant could generate electricity from pipeline natural gas if the gasification block was out of service and the demand for electricity justifies firing of natural gas in the combustion turbines at the plant.[14] The location of the proposed plant in central Illinois meets these objectives.

To achieve its objectives for the proposed plant, Christian County Generation has selected Illinois Basin coal as the design feedstock, coal gasification as the technology to convert coal into SNG, and combined cycle turbines to generate electricity from SNG or natural gas.[15] The decision to use a solid feedstock for the plant is a logical response to the goal of producing SNG. The plant would convert coal, a fuel that cannot be readily used in native form, being restricted in practice to use at power plants and major industrial facilities and institutions, to SNG or natural gas, a clean fuel commodity whose use is ubiquitous. Moreover, the nature of gasification technology is such that the emissions of the gasification process, other than CO_2, are very well controlled, in large part being independent of the composition of the feedstock but instead depending upon the design and performance specifications for the gasification process. Each of these decisions about the design of the

[14] As already discussed, the plant would be able to operate in three primary modes, enabling it to better match the plant's output to the demand for natural gas and electricity. The plant could operate to produce SNG for sale as its objective. In this mode only a single combustion turbine would be operated, as some electric power is needed for the SNG production process. The plant could also operate with generation of electricity from SNG as its objective, with both combustion turbines operating at capacity. Finally, the plant could operate to generate electricity using natural gas when the gasification block is out of service or other circumstances do not warrant production of SNG. As such, the plant would be able to shift its mode of operation in response to changes in the demand for natural gas and electricity, as will certainly occur both during the life of the plant and over shorter time frames (e.g., on a seasonal basis). This flexibility will enhance the value of the plant for purchasers of SNG and electricity from the plant and, as such, should also enhance the economic viability of the plant. The flexibility planned for the plant is reasonable as it will increase the utility and value of the plant.

[15] These objectives are not the same as the original objectives for the plant for which a PSD permit was issued in 2007. The original objective was only to supply electricity to the grid, with development of a plant that was an Integrated Gasification Combined Cycle (IGCC) facility. This change in objectives is in part due to Christian County Generation's goal of also developing a plant that would qualify as a Clean Coal Facility under the Illinois Clean Coal Portfolio Standard Law. The proposed plant being permitted would not use IGCC technology as that term is commonly understood. In particular, the combustion turbines in the power block would not be IGCC generating units, as defined at 40 CFR 60.41Da because they would not be fired on syngas but on SNG. The proposed plant would also have the ability to produce SNG for sale, as well as electricity for the grid.

plant may arguably be considered as part of the BACT determination as "other production processes and available systems and techniques" that could be used to potentially reduce emissions.

DISCUSSION OF GASIFICATION BLOCK SELECTION:

The Gasification Block will have two operating gasifiers using the Siemens dry feed quench gasification technology. The plant will have a single syngas cleanup train including a CO-shift Unit and an AGR Unit using the Rectisol® process. The AGR Unit would remove both sulfur compounds and CO_2 from the raw syngas to produce sweet syngas that is suitable for the Methanation Unit, which will convert the sweet syngas to SNG.

While there are several vendors that supply gasifiers which could have been used for the proposed plant (e.g., General Electric, Siemens, ConocoPhillips), Christian County Generation selected Siemens technology for a variety of reasons. The two main differences between Siemens gasifiers and GE or ConocoPhillips gasification technology are use of a dry coal feed system and a water wall as the insulating liner within the main chamber of the gasifier vessel. Siemens projects higher SNG production per unit input of coal with its dry feed technology, compared to wet or slurry feed systems. Siemens gasifiers should also need less maintenance due to lack of a refractory-lining on the combustion chamber.[16]

The selection of Siemens gasification technology is primarily process focused, but does result in certain environmental benefits. Since Siemens gasifiers will produce more syngas and SNG per ton of feed, they will produce less CO_2 emissions per unit output. The emissions from the gasification block of certain other regulated pollutants, such as CO, NO_X, and SO_2, are not as directly linked to gasifier selection. They are also related to the required performance of the downstream units and the gasification block as a whole. For example, SO_2

[16] As explained by Siemens, in its Siemens Fuel Gasification Technology Brochure, available http://www.energy.siemens.com/hq/pool/hq/power-generation/fuel-gasifier/downloads/brochure_fuel_gasifier_en.pdf, the pneumatic dense phase dry feed system utilized in a Siemens gasifier makes the gasification process more thermally efficient than the slurry fed designs offered by other manufacturers. A dry feed design requires less oxygen consumption which reduces the load for and size of the air separation unit. The water introduced with the coal slurry to a slurry fed gasifier must be evaporated before the water vapor can participate in the gas-phase gasification reactions. The energy required to vaporize water in the slurry is not present with a dry feed system since steam is directly fed to the gasifier at a temperature and pressure that is much closer to the gasification reaction conditions than the liquid water injected with a slurry feed system. A dry feed system also extends the gasifier burner life as compared to a slurry fed burner, which reduces downtime for burner maintenance.

The Siemens gasifier is equipped with a cooling screen or water wall, consisting of spiral-wounded tubes filled with cooling water. This water wall acts as the gasifier insulating media in place of the refractory lining used for GE or ConocoPhillips gasifiers. As molten slag builds up a protective layer on the walls of the cooling screen, liquid slag produced in the gasifier only comes in contact with the solidified slag layer preventing corrosion of the gasifier wall. This innovative design ensures longer gasifier availability between outages for repair or relining than are typically associated with refractory lined gasifiers. Without the need to condition the refractory within the gasifier, a Siemens gasifier can also startup or shutdown much more quickly than refractory lined systems. Rapid changes in lining temperature in a refractory lined gasifier can cause stress and cracking to refractory requiring more frequent maintenance and replacement, and therefore, operators of refractory lined gasifiers must implement specific gasifier preheating practices to ensure the condition of the refractory is not compromised during startup and shutdown.

emissions are also affected by the level of performance required of the AGR Unit and SR Unit.

Some differences in emissions from the secondary operations at the plant do result from the selection of gasification technology. This is readily apparent simply by comparing the emission point list and process flow diagrams for recent SNG projects that use different gasifier technologies. For example, a dry feed Siemens gasification block has coal dryers and lockhopper vents that would not be present in a slurry fed system. On the other hand, refractory lined slurry fed gasifiers have emissions units that would not be associated with a dry feed system including rod mill vents and gasifier vents associated with preheating gasifiers. In the scope of the overall emissions of the plant, the accompanying differences in emissions from secondary operations are considered minor, so as to not warrant further consideration beyond the basic selection of gasification technology.

DISCUSSION OF FEEDSTOCK SELECTION

The selection of gasification technology for the proposed plant has implications for the BACT determination as related to the coal feedstock selected for the plant by Christian County Generation. The coal feedstock selected by an entity proposing to gasify coal may be critical to the economic feasibility and viability of the proposed project, so as to constitute an essential element of that project. This is the case for the proposed plant, for which Illinois Basin coal, available in the area around the plant, is the design coal supply.

One of Christian County Generation's key objectives for the proposed plant is to qualify as a clean coal facility under Illinois' Clean Coal Portfolio Standard Law. This necessitates developing the plant to use a coal feedstock with a "high volatile bituminous rank and greater than 1.7 pounds of sulfur per million btu content." This effectively requires use of Illinois Basin Coal and Christian County Generation will be constructing the proposed plant to use Illinois Basin coal mined in the vicinity of the plant. Low sulfur coals, such as Powder River Basin (PRB) subbituminous or low sulfur Eastern bituminous coals, would not meet the requirements of the law. Although Christian County Generation is currently not subject to the Clean Coal Portfolio Standard Law, it is proposing to develop a plant that would qualify for coverage under the Law, which is still a key objective for the project. Therefore, changing the feedstock to low sulfur coal would fundamentally alter the business purpose and stated goals of the project. Nonetheless, alternative feedstocks were considered in the BACT determination for the plant.

While the gasifiers are theoretically feedstock flexible and could accommodate bituminous, subbituminous, and lignite coal ranks, once the plant has been designed and constructed for a specific feedstock (e.g., Illinois Basis coal), a different feedstock can no longer be used unless the entire gasification block is redesigned and adapted to accommodate it. The gasifiers and the syngas cleanup train will be specifically designed for the moisture, chloride, sulfur, and ash contents and heating value of Illinois Basin bituminous coal. The equipment in the syngas processing train is also designed for the flow rate and composition of syngas that these gasifiers produce when using Illinois Basin coal as a feedstock. Utilizing PRB or low-sulfur Eastern bituminous coal as a feedstock would require a complete redesign of the entire gasification block including the gasifier steam and oxygen supply systems, the water scrubbers designed for chloride removal (and the associated process water balance), and the SR Unit, and potentially the coal milling and drying systems and the gasifier feed systems.[17] Therefore, even though the gasifiers themselves may be "feedstock flexible", nearly all of the process equipment in the coal drying, grinding, and feeding trains, gasifier trains, and syngas conditioning trains will not be compatible with the use of different feedstocks or mixtures of alternate feedstocks including low-sulfur coal.

Putting aside the objectives and design of this plant to qualify for the Clean Coal Portfolio Standard Law, use of a different (e.g., lower-sulfur) feedstock would likely not provide significantly lower emission levels from any emission unit at the plant other than potentially the flare given the process measures employed by the syngas processing trains to remove PM and sulfur compounds from the syngas. The levels of pollutant removal achieved by the syngas processing train are not governed by the levels of contaminants entering the systems but by the level of contaminants that are acceptable in the sweet syngas leaving the system for downstream processing in the Methanation Unit. This is because the methanation catalyst is very sensitive to particulate and sulfur contamination. Due to this required gas cleanup in the gasification block, the sulfur content of the feedstock has little effect on SO_2 emissions during normal operation, other than periods during startup and shutdown. As such, feedstock selection becomes a relevant BACT consideration for startup of the gasification block, and this aspect of feedstock selection is addressed in the

[17] The coal milling and drying process design is specific to the moisture and heating content of the proposed feedstock. Using a feedstock with different characteristics would affect the physical size of the coal milling equipment and the firing rate of the burners in the drying process. Lower heating value coals like PRB would require more coal throughput to achieve the same syngas production rate from the gasifiers. Higher moisture content coals, notably PRB, would require more drying to achieve the target moisture content of the dried coal required to pneumatically convey it to the gasifier feed system. In addition, the particle size of the dried coal is a key parameter for the ability to fluidize the coal in the pneumatic conveying system, so any variations in the friability of potential low sulfur coals as compared to Illinois Basin coal would affect the design of the coal milling and drying process.

The coal bunkers and lockhoppers in the gasifier feed system likewise are sized for specific feedstock characteristics (e.g., the coal throughout and particle characteristics of Illinois Basin Coal). Using coal with a lower heating value would require higher coal throughputs which would need to be considered in designing the equipment in the coal feed system. Similarly, the pneumatic conveyor system is specifically designed for the particle characteristics of the feedstocks, so to the extent that other potential feedstocks would have different particle size and associated fluidizing characteristics these differences would have to be accounted for in the design.

Feedstock heating value, ash content, and mineral matter composition all affect the oxygen and steam demand of the gasifiers. Significant changes in any one of these feedstock properties could affect the size of the air separation unit (ASU) supplying oxygen to the gasifiers and the plant-wide steam balance. The feedstock properties also impact the design of the CO-shift, AGR, and Methanation Units.

The water scrubbers located downstream of the gasifiers are designed to remove particulate, chlorides, and ammonia from the raw syngas. Feeding coal with a higher chloride content to the gasifiers would produce process water with a higher chloride content from the scrubber blowdown that would then have to be treated in the ZLD wastewater treatment system. As such, any significant changes in feedstock chloride levels affect the entire plant-wide water balance and the associated design parameters of the ZLD system.

Finally, the capacity of the SRU is linked to the anticipated sulfur content of the design Illinois Basin coal feedstock. Use of a lower sulfur coal would reduce the size of the SRU.

summary of the SO_2 BACT evaluation for the flare (refer to Part 2 Section 3 of this Attachment).[18]

In addition to alternate coals, biomass is another alternate feedstock warranting consideration in the feedstock selection portion of the BACT analysis since utilizing biomass may result in an emission decrease from certain emission units at the plant. Biomass feedstocks are not, however, appropriate for use at the proposed plant. As a general matter, the composition and properties of biomass are very different than those of coal, which means that biomass is not a suitable feedstock for gasification systems and technology designed to use coal. A key aspect of gasification for production of SNG is consistently producing syngas with the correct ratio of hydrogen and carbon monoxide. The use of biomass also is precluded by the scale of the plant, which is inconsistent with the quantity and nature of biomass that would potentially be available for the plant. Farming to produce low quality biomass feedstocks, of the type that would potentially be used at the proposed plant, is in its infancy; thus, biomass feedstocks cannot yet generally be considered commercial fuels. The continuing availability of such feedstocks and the future cost of such feedstocks cannot be determined or predicted in a way that would allow them to be considered available feedstocks. In this regard, key factors are the nature of government programs that accelerate the development of commercial biomass feedstocks and the extent to which regulations are adopted and programs implemented that increase competition for those resources. Additionally, gasification technology for conversion of biomass into commercial SNG, especially at the scale of the proposed plant, is still in the research and development stage and is not yet technically feasible. Finally, given the level of emissions control required of the proposed plant, the use of biomass feedstock should not be expected to be accompanied by lower levels of emissions of regulated pollutants from many of the emission sources at the proposed plant.

These factors, which preclude use of biomass as the feedstock for the proposed plant, also preclude use of a blend of coal and biomass as the feedstock for the plant. Additionally, use of a blended feedstock, even if feasible, would act to negatively affect the operation of the plant. The increase in the complexity of the gasification process, which would be inherent in using a blend of coal and biomass, would be contrary to consistent and reliable operation, such that an increase in process upsets and flaring should be contemplated.

[18] Even assuming that some level of emissions reduction would be achievable with use of PRB or low-sulfur Eastern bituminous as the feedstock, a plant designed and operated to utilize these alternate coals is expected to be more costly than the current design of the plant relying on Illinois Basin coal as the design feedstock. Illinois Basin coal has a higher fixed carbon content and heating value than PRB, so less Illinois Basin coal is required to produce an equivalent amount of syngas and SNG. USEPA and USDOE both have recognized that the overall costs of a subbituminous coal-based gasification block are higher than a bituminous coal-fired system similar to that proposed for the TEC primarily due to the lower thermal efficiency and higher coal feed rates associated with using subbituminous coal as a gasifier feedstock. USEPA, *Final Report: Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies*, EPA-430/R-06/006, July 2006 and USDOE National Energy Technology Laboratory, *Cost and Performance for Fossil Energy Power Plants, Volume 2: Coal to Synthetic Natural Gas and Ammonia*, July 2011.

DISCUSSION OF COMBINED CYCLE TURBINE SELECTION

Christian County Generation has selected Siemens F-Class turbines for the power block. Only SNG or natural gas will be fired in these turbines. Gas-fired turbines are the most-efficient technology for producing electricity from gaseous fuels, with an efficiency of approximately 50 percent as compared to new coal-fired power plants with an efficiency of 35 - 40 percent.[19] Christian County Generation selected F-Class turbines because this size turbine meets the project design capacity requirements of the Clean Coal Law, and the net power output from a combined cycle plant utilizing F-class turbines is consistent with the expected power demand in the region. Additional discussion of the turbine selection process is provided in Part 3 of this Attachment.

---

[19] USDOE, National Energy Technology Laboratory, *Cost and Performance for Fossil Energy Power Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity*, November 2010.

Part 2: Discussion of BACT for the Gasification Block

1. CO_2 Vent from the Acid Gas Removal Unit

If CO_2 from the gasification process is not sequestered, the CO_2 removed from the raw syngas during cleanup would be vented to the atmosphere at the AGR Unit.[20] The CO_2 vent of the AGR Unit would be the principal source of CO_2 emissions from the gasification block and the production of SNG, contributing over 99 percent of the CO_2 emissions. Along with CO_2, the CO_2 vent stream would also contain CO, VOM and sulfur compounds. The CO would be present because some CO in the raw syngas "travels" with the CO_2 being removed from the syngas by the Rectisol® solvent. When the CO_2-rich solvent is regenerated, the small amount of absorbed CO is also stripped from the solvent and emitted with the CO_2. The sulfur compounds would be present as they are stripped from the solvent along with the CO_2, rather than in the acid gas stream sent to the Unit. VOM, in the form of methanol, would also be present due to carry over of some Rectisol® solvent with the CO_2 stream. As a general matter, the AGR Unit would be designed and operated as practical to minimize emissions of CO, SO_2 and VOM since they would represent losses of material with the CO_2 stream.

Carbon Monoxide (CO)

Add-on catalytic and thermal oxidation systems were examined as available options for reducing CO emissions from the CO_2 vent. Combustion in a boiler was also considered. The evaluation focused on catalytic oxidation, regenerative thermal oxidation, and boilers as approaches that that would minimize the amount of supplemental fuel used for control of CO. Boilers were determined to be less effective than oxidizers systems, with only 98 percent CO control efficiency from the uncontrolled design concentration.[21] Catalytic and regenerative thermal oxidation are considered equally effective, with both capable of achieving CO control efficiency of up to 99 percent. Significant adverse energy, environmental, or economic impacts that would affect the BACT determination were not identified for either type of oxidation.[22] Christian County Generation has selected catalytic oxidation to control CO emissions in the CO_2 vent stream based on lower costs. A CO BACT limit of 36.6 lb/hr, 3-hour average, is proposed based on the maximum CO loading in the uncontrolled stream and a control efficiency of 99 percent. This limit was determined to be equal to or more stringent than CO BACT limits for the CO_2 vent streams at other similar facilities that have recently been permitted.

Volatile Organic Material (VOM)

---

[20] The selective venting of CO_2 from the AGR Unit, which removes both CO_2 and sulfur compounds from the raw syngas, is possible because regeneration of the Rectisol® solvent for reuse in the AGR Unit would occur in two stages. CO_2, which does not bond as strongly to the solvent as sulfur compounds, is stripped off in a first stage. This stream would be discharged to the atmosphere from the "CO_2 vent" on the AGR Unit if and when CO_2 is not being sequestered. Sulfur compounds, which bond more strongly to the solvent than CO_2, would be stripped off in a second "hot" regeneration stage, producing the stream of acid gas that would be sent to the SR Unit.

[21] In addition to consuming fuel, a boiler would generate additional steam that the plant does not need.

[22] Catalytic oxidation would be ranked slightly better than regenerative thermal oxidation. This is because combustion of CO, VOM and supplemental fuel, as facilitated by the catalyst, would occur flamelessly at a relatively low temperature, without thermal formation of NO_X.

Because of carryover of Rectisol® solvent, the CO_2 vent stream from the AGR Unit will also contain VOM at low concentrations. The control options for the CO are also applicable for VOM in this stream. Catalytic oxidation was selected as the BACT technology for VOM as well. The proposed VOM BACT limit is 1.03 lb/hr, 3-hr average (4.01 lb/hr for startup and shutdown) based on the maximum design VOM loading in the stream and a VOM control efficiency of 90 percent. A lower control efficiency is present for VOM, compared to CO, because the VOM concentration in the inlet stream will be lower than the CO concentration.

Sulfur Dioxide (SO_2)

With the use an oxidation system as BACT for CO and VOM, the H_2S and COS in the uncontrolled stream, present at very low concentrations, will be converted to SO_2. As this stream has already undergone processing with Rectisol® technology in the AGR Unit to remove sulfur compounds, additional upstream control technologies are not available to further process this stream to reduce its H_2S and COS content beyond the already very low levels achieved with the AGR Unit. Add-on, post-combustion SO_2 control technologies are also not available for SO_2 emissions in the oxidizer exhaust. As such, the only available control options for the CO_2 vent of the AGR Unit are proper operation of the unit and use of low-sulfur fuels (i.e., sweet syngas, SNG or natural gas, as the supplemental fuel for the oxidation system). The proposed SO_2 BACT limit based on these measures is 29.2 lb/hr, 3-hour average (36.5 lb/hr for startup and shutdown).

Particulate Matter (PM)

The particulate matter emissions of the CO_2 vent of the AGR Unit are the byproduct of supplemental fuel used in the catalytic oxidizer for this vent stream. Use of good combustion practices and clean supplemental fuel are the only available and technically feasible control options. A BACT limit of 0.06 lb/hr, 3-hour average, for PM, PM_{10} and $PM_{2.5}$ is proposed with these control measures.

Carbon Dioxide (CO_2)

If CO_2 is not sequestered, the CO_2 vent of the AGR Unit would be the principal source of CO_2 emissions from the gasification block and the production of SNG, contributing over 99 percent of the CO_2 emissions. Christian County Generation evaluated carbon capture and sequestration (CCS), gasification block process efficiency, and feedstock selection as possible control options to reduce CO_2 emissions from the CO_2 vent.

Because capture or separation of CO_2 is inherent in coal gasification for production of SNG,[23] [24] the critical issue for implementing CCS at the proposed plant is sequestration of the CO_2 stream. Sequestration involves transporting and geologically sequestering the CO_2 through various means such as enhanced oil recovery (EOR), saline aquifers, and sequestration in un-minable coal

[23] Separation of CO_2 from the raw syngas is inherent to the production of SNG when using coal gasification and methanation. This is because the process of converting syngas to methane in the Methanation Unit is sensitive to the CO_2 content of the syngas.
[24] Demonstrated technology exists for separation of CO_2 from syngas, as developed in the natural gas and chemical industries. CO_2 is currently separated from the syngas at four coal gasification plants currently operating in the United States: Coffeyville Resources, Coffeyville Kansas (ammonia), Air Products (purified syngas), Dakota Gasification, Beulah, North Dakota (SNG), and Eastman Chemical, Kingsport, Tennessee (chemical intermediates).

seams. There are additional methods of sequestration such as direct ocean injection of CO_2 or reactions to form solid carbonates; however, these methods are conceptual and not available for full-scale applications.

While enhanced oil recovery (EOR) may be available for certain projects, the limiting factor for the application of CCS to the proposed plant is the availability of a mechanism (pipeline or geologic formation) at this time to permanently sequester the captured CO_2 from the CO_2 vent on the AGR Unit or captured CO_2 from any other emissions points that are candidates for capture.

Three full-scale IGCC projects (Summit Texas Clean Energy, Southern Company Kemper County, and Hydrogen Energy California) have been recently proposed to commercially demonstrate the use of CCS under the United States Department of Energy's (USDOE) Clean Coal Power Initiative (CCPI).[25] The proposed plant is not one of these projects.[26,27]

As discussed in an August 2010 report by the federal Interagency Task Force for Carbon Capture and Storage, four fundamental near-term and long-term concerns exist for the full-scale commercial application of CCS:[28]

- The existence of market failures, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions.
- The need for a legal/regulatory framework for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO_2 can be stored safely and securely.
- Clarity with respect to the long-term liability for CO_2 sequestration, in particular regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages.
- Integration of public information, education, and outreach throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers.

[25] As described by the USDOE on its website, "The mission of the Clean Coal Power Initiative (CCPI) is to enable and accelerate the deployment of advanced technologies to ensure clean, reliable, and affordable electricity for the United States. The CCPI is a cost-shared partnership between the Government and industry to develop and demonstrate advanced coal-based power generation technologies at the commercial scale. CCPI demonstrations address the reliability and affordability of the Nation's electricity supply, particularly from its coal-based generation."

[26] Tenaska's proposed Trailblazer project, a planned coal-fired boiler power plant near Sweetwater, Texas that would capture CO_2 for use for enhanced oil recovery, also is currently not a part of the USDOE's CCPI.

[27] The USDOE's CCPI is different from the USDOE's loan guarantee program for which the proposed plant is a candidate. As described on the USDOE website, "DOE's Loan Guarantee Program, authorized by Title XVII of the Energy Policy Act of 2005 (EPAct), aims to facilitate early commercial use of new or significantly improved technologies in energy related projects. Projects supported by loan guarantees will help fulfill President Bush's goal of reducing our reliance on imported sources of energy by diversifying our nation's energy mix, increasing energy efficiency, and improving the environment. Section 1703 authorizes the U.S. Department of Energy to support innovative clean energy technologies that are typically unable to obtain conventional private financing due to high technology risks. In addition, the technologies must avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases."

[28] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf,, p. 53.

Given the unresolved issues for CO_2 sequestration, as discussed in this report, CCS was eliminated from consideration as a BACT control option for CO_2 emissions from the CO_2 vent based on technical infeasibility.[29]

The fact that Dakota Gasification's Great Plains Synfuels plant (Great Plains) sequesters some of its CO_2, with sale for use for EOR, does not show that sequestration is feasible for the proposed plant or is generally feasible.[30] The circumstances of Great Plains are significantly different from those of the proposed plant. In particular, there currently is not a market for CO_2 from the proposed plant for EOR since CO_2 is not used in Illinois for EOR.[31] Other than a few small-scale pilot projects, Illinois oil producers have no experience with conducting EOR at oil fields in the Illinois Basin. EOR has not been deployed commercially in Illinois oil fields because the existing EOR practices cannot produce higher oil recovery rates in an economical manner.[32] The closest existing CO_2 pipeline to the proposed plant is located approximately 400 miles away in Mississippi (where EOR can be used to produce higher oil yields at a reasonable cost). Without an existing CO_2 pipeline nearby, Christian County Generation is reliant upon third-party CO_2 off-takers to make CCS for EOR a viable control option. Denbury Resources has announced plans to construct a Midwest CO_2 pipeline to connect proposed gasification projects in the Midwest to EOR sites in the Gulf Coast Region.[33] Denbury Resources has indicated that the development of this pipeline, which may make carbon sequestration feasible at some time during the lifetime of the proposed plant, is contingent on the presence of at least one other nearby, large industrial source that would supply CO_2 to the pipeline. CCS using EOR cannot be required as BACT for CO_2 emissions from the CO_2 vent on the AGR Unit, since no CO_2 pipeline exists today and Christian County Generation has no control over CO_2 capture projects in Illinois or adjacent states. Assuming that another gasification plant will be built near the proposed plant (e.g., Power Holdings near Waltonville, Illinois) and will come online in the same timeframe as the plant is speculative and cannot be relied upon in establishing BACT for the proposed plant.

---

[29] The Illinois Clean Coal Portfolio Standard Law requires the Illinois Commerce Commission to submit a report to the General Assembly setting forth its analysis of a ***Facility Cost Report*** filed by the initial clean coal facility in Illinois. In an attempt to qualify as the "initial clean coal facility", Christian County Generation submitted a facility cost report for the TEC which evaluated the economic, energy, and environmental impacts of implementing CCS in the Mt. Simon sandstone formation located in the vicinity of the project (refer to Exhibits 13.2a and 13.2b at http://www.icc.illinois.gov/electricity/tenaska.aspx)

[30] The Great Plains Synfuels plant in Beulah, North Dakota, is a lignite gasification plant with a SNG capacity similar to that of the proposed plant. The plant began operation in 1984. In 2000, a portion of the CO_2 from the plant began to be used for enhanced oil recovery in the Weyburn and Midale oil fields in Saskatchewan, Canada. The CO_2 is transported through a 205-mile pipeline, with the goal of selling at least 60 percent of the CO_2 produced by the plant.

[31] The Midwest Geological Sequestration Consortium (MGSC), one of seven regional partnerships selected by the U.S. DOE to determine the best approaches for capturing and storing CO_2, was established to assess geological carbon sequestration options in the Illinois Basin. One of the objectives of the MGSC is to identify oil reservoirs with suitable characteristics and oil properties for EOR (refer to http://sequestration.org/).

[32] USDOE, ***Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Illinois and Michigan Basins***, February 2006.

[33] NIU Regional Development Institute, Economic Impacts of a Midwest CO_2 Pipeline: Construction, Easement, and Operational Impacts, October 30, 2009, available at http://www.coaltransition.org/filebin/pdf/Midwest_Pipeline_Feasibility_Study_Summary_and_Findings_with_Exhibits_3.12.10.pdf

A second approach to sequestration of CO_2 from the CO_2 vent on the AGR Unit would be geologic sequestration in sandstone in the Mt. Simon formation, which is present deep underground in the region in which the plant is located. A detailed feasibility study of this sequestration option for the plant was performed by Schlumberger Carbon Services in February 2010 to evaluate: 1) whether the proposed site has capacity to sequester the expected volume of CO_2 from the plant, 2) containment of the sequestration reservoir, and 3) infrastructure requirements for sequestration (number and dimensions of injection wells, operational strategies, etc.)[34] Although the results of this preliminary study were favorable, many other technical issues associated with geologic CO_2 sequestration still need to resolved. In addition, there are unresolved issues involving the regulatory requirements for sequestration and liability associated with sequestration. Further development of sequestration is needed before a BACT emission limit could be set for the proposed plant that is predicated upon implementation of CCS.[35]

The fact that the plant would potentially have been required to capture and sequester a certain portion of its CO_2 emissions to qualify as a "clean coal facility" and receive certain benefits under the Clean Coal Portfolio Standard Law also does not show that sequestration is currently feasible for the plant. This is because this act did not reflect a determination that sequestration was feasible, addressing the considerations that are relevant to a case-by-case determination of BACT for a proposed project. Rather, this act set a criteria for sequestration of CO_2 from the plant that, if met, would have entitled Christian County Generation to certain financial benefits for the operation of the plant under state law.[36]

The third approach to BACT that was considered for CO_2 emissions was the conversion or process efficiency of the gasification block. The most direct measure of the process efficiency of the gasification block as related to CO_2 emissions is the rate of CO_2 emissions from the AGR Unit vent per unit of SNG produced by the gasification block or, in more convenient terms, tons of CO_2

[34] Schlumberger Carbon Services, Summary Results for Carbon Storage Feasibility Study Taylorville Energy Center, February 23, 2010 presented in the Facility Cost Report as Exhibit 13.2.a available at http://www.icc.illinois.gov/electricity/tenaska.aspx

[35] Notably, to address potential impacts of CO_2 sequestration on groundwater, as groundwater may be a resource for drinking water, USEPA recently adopted provisions under its Underground Injection Control (UIC) program to address CO_2 Geologic Sequestration Wells. his rulemaking established a new class of well, Class VI wells, with associated requirements addressing minimum technical criteria for permitting, geologic site characterization, area of review and corrective action, financial responsibility, well construction, operation, mechanical integrity testing, monitoring, sealing of wells, post-injection site care, and site closure of such wells. These requirements are tailored to address the specific characteristics of CO_2 when its sequestered, including the large volume of material, the buoyancy and viscosity of CO_2, and its chemical properties, as compared to materials previous addressed under the UIC program,. Based on these new rules, it is unclear whether Christian County Generation will be able to obtain an injection well permit in a timely manner, and even if a permit is obtained, whether Christian County Generation will be able to sequester CO_2 from the plant in the Mt. Simon formation under the UIC program. Therefore, for the purposes of BACT, carbon sequestration in the Mt. Simon formation or any other candidate geologic sequestration site was eliminated from consideration as a control option for reducing CO_2 emissions from the AGR Unit vent.

[36] The Clean Coal Portfolio Standard Law also would have provided for Christian County Generation to make monetary payments to the State of Illinois if the applicable sequestration levels were not achieved by the plant. In the context of the PSD rules, these monetary payments contemplated under Illinois Law cannot stand in place of compliance with requirements for control of emissions that are established as BACT.

per million scf of SNG produced.[37] In order to demonstrate the efficiency of the gasification block at the plant, Christian County Generation compared the plant's CO_2 mass emissions from the CO_2 vent as a function of SNG output to other recently proposed SNG projects using bituminous coal as a feedstock. SNG facilities using other feedstocks such as petroleum coke and lower rank coals cannot be considered in the evaluation since the differing characteristics (i.e., primarily carbon, ash, and moisture content and heating value) of these other feedstocks affects the SNG yield and CO_2 emissions. The results of the analysis demonstrated the plant's gasification block has the lowest SNG output-based CO_2 emissions. Based on the design of the proposed gasification block and selection of sweet syngas as the fuel to supply heat to the oxidizer for the CO_2 vent from the AGR Unit, a BACT limit of 111.4 tons CO_2e/million scf SNG produced on an annual average basis is proposed.

Greenhouse Gases (Methane)

Since methane will not be present in the CO_2 vent stream, the only available control option for reducing methane emissions from the oxidation system for AGR Unit vent is good combustion practices to ensure complete combustion of the supplemental fuel. Christian County Generation will utilize good combustion practices for the catalytic combustion system to comply with the proposed SNG-output based BACT limit for the AGR Unit CO_2 vent, which includes the contribution to GHG emissions from methane.

2. Sulfur Recovery Unit

The Sulfur Recovery Unit (SR Unit) receives the acid gas stream, which is laden with hydrogen sulfide (H_2S), from the AGR Unit, and converts it into elemental sulfur. The SR Unit will use the Claus process, which is routinely used at petroleum refineries to treat acid gas streams produced from the desulfurization of gasoline, fuel oil, and other petroleum products. In this process, a portion of the H_2S in the acid gas stream is combusted and the resulting SO_2 and the remaining H_2S in the stream are combined in a catalytic reaction that yields elemental sulfur and water. The SR Unit is potentially a source of SO_2 emissions because not all the sulfur present in the acid gas stream can be converted into elemental sulfur. A small amount of the sulfur, as SO_2, is present in the tailgas stream.

During normal operation of the gasification block, the tailgas from the SR Unit itself will be routed to a tailgas unit and then recycled back to the inlet of the AGR Unit. In the tailgas unit, the residual SO_2 in the tailgas will be converted back to H_2S with a catalyst. The only emissions from the thermal oxidizer on the SR Unit during normal operation are from combustion of supplemental fuel to keep the oxidizer ready for any upsets in the operation of the recycle system and trace SO_2 and combustion byproduct emissions from combusting the H_2S in certain low volume sour process streams. During a cold plant startup, the acid gas produced by the AGR Unit before the CO Shift Unit comes online will not be of sufficient quality or quantity to be processed in the SR Unit and, therefore, this acid gas stream will be routed directly to the thermal oxidizer and subsequently to the caustic scrubber. During startup of an SR Unit, the Claus process can take several hours to reach steady-state sulfur removal such that the SO_2 in the tailgas can be converted back to H_2S,

[37] Addressing CO_2 emissions in terms of SNG output, rather feedstock input to the gasification block, simplifies the expression of process efficiency. This is because it bypasses the potential need to consider variability in the heat or carbon content of the coal feedstock to the gasification block.

compressed, and recycled to the inlet of the AGR Unit. Until the tailgas meets the operational requirements for processing in the tailgas unit, the tailgas is routed to the oxidizer to convert residual H_2S to SO_2 which is subsequently removed in the scrubber. Based on the maximum number of SR Unit startups that Christian County Generation projects would occur annually, the oxidizer for the SR Unit is only expected to emit 3.1 tpy of SO_2.

Sulfur Dioxide (SO_2)

Control options evaluated for SO_2 emissions from the SR Unit were tailgas recycle to the AGR Unit, a thermal oxidizer and scrubber system, liquid reduction/oxidation (redox) processes, amine-based absorption, oxidative wet scrubbing, and alternative designs of the Claus process.[38]

A two-stage Claus design with tailgas recycle is the top control option for reducing SO_2 emissions associated with tailgas from the SR Unit. It is followed by an oxidizer and scrubber system and then various other refinery-type treatment options for tailgas from sulfur recovery units. Both of the top technologies for the SR Unit will be utilized at the plant. Tailgas recycle to the AGR Unit will be used for normal operation, and oxidation and scrubbing will be used when the SR Unit tailgas cannot be recycled to the AGR Unit. In comparison to the energy and environmental impacts associated with the other candidate control technologies that are ranked below tailgas recycle and an oxidizer/scrubber, neither the energy consumption of the oxidizer and scrubber nor the presence of the wastewater and combustion byproduct emissions streams should disqualify the oxidizer and scrubber as the top control option for treating tailgas when it cannot be recycled to the AGR Unit.

With a tailgas recycle system, proposed SO_2 BACT limits for the oxidizer/ scrubber on the SR Unit are 0.63 lb/hr, 3-hour average (64.4 lb/hr, during startup, shutdown and malfunction). An annual SO_2 BACT emission limit of 3.05 tpy, on a 12-month rolling basis, including all periods of operation, is also proposed.

A number of factors preclude imposition of a single short-term SO_2 BACT limit for this oxidizer that applies at all times. Most significantly, the SR Unit and tail gas treatment unit are sophisticated chemical processes, which cannot achieve the same level of performance during the transitory conditions of startup, shutdown or malfunction, as achieved during normal, steady-state operation. Recognizing the inherent nature of these units during startup, shutdown and malfunction, separate BACT limits and work practices are proposed (refer to Draft Condition 4.1.5-2) that are intended to assure that appropriate measures are taken during such periods to minimize emissions.

Carbon Monoxide (CO) and Volatile Organic Material (VOM)

CO and VOM emissions from the oxidizer on the SR Unit can form as a result of incomplete combustion of any CO and hydrocarbons in the process streams routed

[38] The use of liquid redox technology was eliminated due to considerations of technically feasibility. A direct consequence of the use of a two-stage Claus process in the SR Unit, as needed for a tailgas stream whose sulfur content is high enough for it to be recycled back to the inlet of the AGR Unit, is that sulfur content of the tail gas stream is too high for liquid redox technology.

to it and as a result of supplemental fuel combustion in the oxidizer. The only available control option for reducing CO and VOM emissions from the already low levels achieved in the oxidizer is good combustion practices which include proper burner and thermal oxidizer design, good burner maintenance and operations, and good air to fuel ratio control to promote efficient oxidation. Based on the use of these good combustion practices, the proposed short-term CO BACT limit for the oxidizer on the SR Unit is 1.39 lb/hr, 3-hour average (19.0 lb/hr for startup and shutdown). The proposed short-term VOM BACT limits is 0.038 lb/hr, 3-hour average, (20.7 lb/hr, for startup and shutdown). Annual CO and VOM BACT emission limit are also proposed, 6.25 and 0.27 ton/year, respectively, on a 12-month rolling basis.

Nitrogen Oxides (NO_X)

During normal operation, the process gas streams routed to the oxidizer on the SR Unit would not contain any nitrogen compounds that may form fuel NO_X in the oxidizer, so only thermal NO_X emissions from supplemental fuel combustion are expected. During startups and shutdowns, the process gas routed to the SR Unit will contain trace levels of ammonia, which will contribute to additional NO_X formation in the oxidizer. All of the add-on NO_X control technologies typically applied to reduce NO_X emissions from gas-fired combustion equipment (i.e., SCR, SNCR, etc.) are infeasible for this oxidizer because of the low concentrations of NO_X in the oxidizer exhaust. In addition, a review of entries for oxidizers for SR Units in the Clearinghouse did not identify any add-on controls used as BACT for NO_X emissions. Other facilities have, however, proposed low-NO_X burners for reducing NO_X emissions from this oxidizer. With low-NO_X burners, the proposed NO_X BACT limit is 0.35 lb/hr, 3-hour average (2.48 lb/hr for startup and shutdown). An annual NO_X BACT emission limit of 1.55 tpy, 12-month rolling basis, is also proposed.

Particulate Matter (PM)

Particulate matter emissions from the oxidizer on the SR Unit are formed as byproducts of supplemental fuel combustion, and as such, good combustion practices are the only available and technically feasible control option for reducing PM emissions from this device. The proposed PM, PM_{10}, and $PM_{2.5}$ BACT limit for this oxidizer is 0.053 lb/hr, 3-hour average (0.38 lb/hr during startup and shutdown). An annual BACT limit is also proposed, 0.24 tpy.

Greenhouse Gases (Carbon Dioxide (CO_2), methane and nitrous oxide (N_2O))

CO_2 emissions from the oxidizer on the SR Unit will occur from combustion of organic compounds in the process streams routed to this oxidizer and as a result of supplemental fuel combustion. Control options evaluated for reducing CO_2 emissions from the oxidizer include CCS, tailgas recycle, fuel selection, managing fuel consumption and good operating practice (i.e., maintaining the carbon content of the process gas at a level consistent with the design basis of the BACT limit).

Post-combustion capture for removal of CO_2 from the dilute and highly variable flow rate exhaust from this oxidizer is not a demonstrated control option. Furthermore, even if post-combustion capture were available, the limiting factor is the availability of a mechanism (pipeline or geologic formation) at this time for the plant to permanently sequester the captured CO_2 from this oxidizer. Since CCS is not considered a technically feasible technology, it was eliminated from further consideration in the remaining steps of the analysis. Each of the other remaining control options is technically feasible and will be utilized to achieve compliance with the CO_2 BACT limit. Most significantly, recycle of tailgas from the SR Unit back to the AGR during normal operation will minimize the loading placed on the oxidizer and the amount of supplemental fuel that must be fired in the oxidizer.

Methane emissions will occur from this oxidizer due to incomplete combustion of methane in the process streams routed to this oxidizer and in the supplemental fuel gas, with annual potential methane emissions projected to be 9.3 tons. The only available control options for reducing these emissions are good combustion and operating practice (i.e., managing fuel consumption to maintain a high level of combustion efficiency). While this may slightly increase CO_2 emissions due to the increased conversion of methane to CO_2 associated with high combustion efficiency, the overall GHG emissions on a CO_2e basis decrease with complete combustion of the fuel and the small amounts of methane in the process gas. The implementation of good combustion and operating practices will appropriately control methane emissions from the oxidizer.

Both fuel and thermal N_2O emissions are expected from combustion of supplemental fuel by this oxidizer. Research into N_2O control options for a variety of industrial source types did not reveal any available add-on controls specifically for N_2O emissions from oxidizer. The lack of demonstrated add-on controls for N_2O for stationary combustion sources is supported by a comprehensive 2008 study of non-CO_2 GHG emissions control measures conducted by the California State University for the California Air Resources Board (CARB). In this study, only reduced N_2O emissions from fluidized bed combustion, utilizing SCR in place of SNCR, fuel switching, and reduction in fossil fuel consumption were identified as available N_2O control measures.[39]

The potential annual N_2O emissions of this oxidizer are only 0.068 tons. Low-NO_x burners (LNB)[40] were selected as BACT control to minimize NO_x formation in this gas-fired oxidizer. As LNBs reduce NO_x formation, they theoretically promote N_2O formation, resulting in a tradeoff between control of NO_X and N_2O. However, a literature search did not identify information from oxidizer burner or other combustion device burner manufacturers recommending procedures to minimize N_2O formation. Given the general preference to mitigate emissions of NO_x in instances where small tradeoffs between emissions of NO_x and GHG are present, the draft permit would require that this oxidizer be operated with LNB utilizing good combustion practices in a manner that minimizes NO_X formation and will not specifically target N_2O reductions through burner selection and operating practices.

Ammonia in the process gas routed to the oxidizer on the SR Unit during startups and shutdowns has the potential to convert to N_2O in the device. Good operating practices to maintain the ammonia content of the process gas at a level consistent with the design basis used to establish the proposed BACT limit will act to minimize N_2O formation by this mechanism.

Based on these considerations, the proposed CO_2e BACT limit for the oxidizer is 4,937 tons per year, 12-month rolling basis.

[39] Kuo, Jeff, Dept. of Civil and Environmental Engineering California State University, Fullerton, ***Clearinghouse of Technological Options for Reducing Anthropogenic Non-CO2 GHG Emissions from All Sectors*** (Contract No.: CARB 05-328), May 14, 2008, http://www.arb.ca.gov/research/apr/past/05-328.pdf

[40] Low-NO_x burners (LNBs) manage or manipulate mixing of fuel and air to create larger and more branched flames containing distinct combustion zones, so to stage combustion. Staged combustion reduces peak flame temperature resulting in less NO_X formation.

3. Flaring during Startup, Shutdown and Malfunction

During startup, shutdown or malfunction of the gasifiers, "off-specification" process gas streams (i.e., raw syngas and various other streams), which are not acceptable for normal processing, must be safely disposed of by flaring. A malfunction of the methanation unit could also require flaring of cleaned syngas or SNG that does not meet specifications. Even though off-specification syngas must be flared, it is expected that most flared syngas will still have undergone some level of cleanup, especially particulate cleanup with water wash or scrubbing. Work practice requirements and emission limits are proposed as BACT to address this flaring during startup, shutdown and malfunction.

The required BACT work practices for flaring are intended to assure that appropriate measures are taken to minimize emissions during startup, shutdown and malfunction. For this purpose, certain basic measures are proposed that must be used to minimize emissions. A general approach to minimization of emissions is also proposed 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 would be use of SNG or natural gas as the fuel for the pilot burners in the gasifier. Another aspect of BACT for flares would be operating in accordance with good air pollution control practices to ensure effective destruction of CO, organic compounds, and reduced sulfur compounds present in gas streams that are being flared.

For typical hydrocarbon flares in the refinery and chemical industries that control high-Btu process gases, the most common good air pollution control practice is to implement the requirements of 40 CFR 60.18 as required by the NSPS standards for these industries. Due to the relatively high volumetric flow rate and low heat content of syngas vented to the flare during certain periods of startups and shutdowns, Christian County Generation does not expect to be able to always comply with the minimum heating value and maximum exit velocity requirements of 40 CFR 60.18, and as such alternative good air pollution control practices are proposed during these periods (refer to Draft Conditions 4.1.2-1(b)(vi), 4.1.7-1(c),4.1.8-2(g)(v)). The visual observations would be required to be conducted during flaring events, for which compliance with 40 CFR 60.18 is not possible, to ensure adequate combustion is occurring by verifying good flame stability and no separation of the flare flame from the flare tip.

The hourly and annual flare emission limits that are set as BACT for periods of startup, shutdown and malfunction are expressed in pounds per hour and tons per year. 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/IGCC plant, in which syngas is produced for immediate transfer to the methanation unit and subsequent transfer to the pipeline or as fuel to the combustion turbines, 2) the stringent levels of control that are normally required of the units, and 3) the limited operational experience with SNG and/or IGCC 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.

Given the continuous compliance requirements that are included in the draft permit (i.e., continuous off-specification process gas flow rate and H_2S monitoring, periodic process gas sampling, emission calculations and recordkeeping requirements for all flare events, etc.), the annual BACT limits inherently limit the frequency and duration of the various types of gasification block startup and shutdown events identified in the Application. If Christian County Generation were to conduct more startups and shutdowns than originally envisioned in the Application or if startups and shutdowns routinely exceeded the duration assumed in the Application, potential violations of the annual BACT limits could occur. In this situation, Illinois EPA will have ready access to all of the necessary flare emission data to determine if the TEC is in compliance with both the hourly and annual emission limits that are applicable to the flare without the need to establish specific lb/event emission limits or hr/event operating limits for gasification block startups and shutdowns.

Sulfur Dioxide (SO_2)

Flare Minimization Planning, Root Cause Analysis, use of alternative low sulfur feedstocks during startup of gasifiers, amine-based absorption, and good flare design (including operating in accordance with the flare manufacturer's recommendations, an alarm system for pilot flame loss, automatic pilot flame reignition system, and use of SNG and natural gas fired pilots) were evaluated as BACT control options for SO_2 from the flare.

Use of low sulfur feedstock, e.g., Powder River Basin Coal, during startup and shutdown was eliminated from detailed consideration based on lack of effectiveness and technical infeasibility for the selected gasification technology. Switch to an alternative feedstock during shutdown would immediately trigger venting to the flare. Even though the gasifiers would theoretically be capable of using lower-sulfur coal at the beginning of a startup, the purpose of a startup is to expeditiously begin or transition to normal operation of the gasification block on the design feedstock. The use of an alternative feedstock for startup would act to prolong the overall duration of startup. This is because it would add an additional step to the startup process, switching from the startup feedstock to the design feedstock, increasing the length of time during which off-specification process gas streams would have to be flared. The use of an alternative startup feedstock would also likely require entirely separate, parallel coal drying, milling, and feeding systems, with additional features to switch between the normal feed system for the gasifiers and the "startup system" for the gasifiers. This would further extend the duration of startup as transition would be needed for both the gasification block and the associated feed systems. Accordingly, an alternative feedstock to the principal feedstock, i.e., Illinois Basin coal, is not considered a feasible control measure for startup.

Amine-based absorption was eliminated on the basis of both technical infeasibility and the minimal effectiveness that is expected. Routing raw or sour syngas to an amine scrubber during startup and shutdown is only a technically feasible control option for reducing SO_2 emissions from the flare if it is not possible to process the sour syngas in the much more efficient Rectisol® AGR Unit. Routing raw syngas (i.e., syngas before wet scrubbing and sulfur removal) to an amine absorption system during startups and shutdowns is not technically feasible under any circumstances because the relatively high level of particulate in the syngas would foul the absorber. During the short periods of startup and shutdown events when sour syngas (i.e., syngas after wet scrubbing but before sulfur removal) is routed to the flare, amine-based absorption is not expected to be an effective control option for SO_2 emissions from flaring.

Flare minimization planning, Root Cause Analysis, and good flare design were selected as the BACT level work practice options to accompany the hourly and annual BACT limits established for the flare. The proposed hourly and annual SO_2 BACT limits for the flare are 9,036 lb/hr, 3-hour average, and 551 tpy, 12-month rolling basis, respectively.

Carbon Monoxide (CO) and Volatile Organic Material (VOM)

Flare Minimization Planning, Root Cause Analysis, and good flare design were evaluated as BACT control options for minimizing emissions of CO and VOM from the flare. All of these options were selected to support the hourly and annual CO BACT limits of 4,633 lb/hr, 3-hour average, and 315 tpy, 12-month rolling basis, respectively.

Nitrogen Oxides (NO_X)

The off-specification gas streams routed to the flare will not contain NO_X. The collateral NO_X emissions generated by flaring these gases, as necessary for safety, were addressed in the flare BACT analysis. Just as for CO and VOM, Flare Minimization Planning, Root Cause Analysis, and good flare design were selected to support the hourly and annual NO_X BACT limits of 129.8 lb/hr, 3-hour average, and 8.51 tpy, 12-month rolling basis, respectively.

Particulate Matter (PM)

PM emissions will occur both as a product of incomplete combustion and due to the particulate in sour syngas vented to the flare for a brief period during startups and shutdowns. As such, pre-flare water wash or wet scrubbing and high temperature candle filtration were evaluated in addition to good flare design as possible control options for PM. Wet scrubbing and candle filtration are expected to be equally effective at reducing PM emission from the flare. Wet scrubbing was selected as the BACT technology based on operational considerations. Wet scrubbers and good flare design were selected to support the hourly and annual BACT limits of 360.7 lb/hr, 3-hour average, and 2.95 tpy, 12-month rolling basis, respectively.

Carbon Dioxide (CO_2)

Carbon capture and sequestration (CCS), Flare Minimization Planning, Root Cause Analysis, fuel selection, and good flare design were evaluated as possible means to minimize CO_2 emissions from flaring.

As addressed in the discussion of BACT for the AGR Unit CO_2 vent, CCS was generally eliminated from consideration in the BACT analysis since it is not commercially available at the scale required for the proposed plant. Furthermore, pre-combustion capture has not been demonstrated for removal of CO_2 from intermittent and dilute (i.e., low CO_2 concentration) process gas streams routed to a flare regardless of whether or not a permanent sequestration site is available for the plant.

Pipeline quality natural gas and SNG, which has a comparable GHG emissions profile to pipeline quality natural gas, represent the available pilot and supplemented fuel types for the flare with the lowest carbon intensity on a heat input basis (i.e., lowest emission factor in units of lb/mmBtu).

Therefore, selecting these fuels was evaluated as an available control option for reducing CO_2 emissions from the flare.

Flare minimization planning, RCA, and fuel selection were determined to be the only feasible control options to reduce CO_2 emissions. An annual average secondary CO_2e BACT emission limit from the flare (26,387 tpy CO_2e, 12-month rolling basis) was established to support the selected work practices.

Greenhouse Gases (Methane and Nitrous Oxide (N_2O))

Like CO and VOM, methane emissions from the flare will be formed as a secondary combustion byproduct and due to incomplete combustion of methane present in the process gases vented to the flare. Accordingly, Flare Minimization Planning, Root Cause Analysis, and good flare design were also selected as BACT for methane. A separate annual BACT emission limit for methane was not established since methane emissions are addressed in the CO_2e limit.

Similar to NO_X, off-specification process gas routed to the flare from the gasification block will not contain N_2O. However, since the flare is required to safely dispose of off-specification process gas and to meet BACT requirements for criteria pollutant emissions, the collateral N_2O emissions generated by the flare were addressed in the flare BACT analysis. Flare minimization planning, RCA, good flare design, and good operating practices were evaluated as available measures to reduce N_2O emissions from the flare. Good operating practices for reducing N_2O emissions from the flare refers to maintaining the ammonia (NH_3) content of the process gas at a level consistent with the design basis used to establish the proposed BACT limit. This operating requirement will act to minimize N_2O formation by the fuel-bound mechanism. Each of the identified control options will be required as BACT for N_2O emissions as addressed in the annual CO_2e BACT limit for the flare.

In addition to differences in emission points, GE gasifiers are equipped with patented liquid-fueled gasifier burner technology that allow the gasifiers to startup on sulfur-free liquid fuels such as methanol. Although this proprietary technology may reduce SO_2 emissions from flaring off-specification gas during gasifier startups, the technology is not available to other gasifier vendors. Also, the potential environmental benefit of less SO_2 emissions from flaring in a GE gasification block could be more than offset by emissions increases in other locations of the plant associated with the lower thermal efficiency and longer startup and shutdown durations. In fact, the sum of the plant-wide annual emissions of all PSD regulated pollutants including greenhouse gases from the current project design based on Siemens gasification are lower than the previous design based on GE gasification.

Part 3: BACT Discussions for the Power Block

The following discusses BACT for the two combustion turbines in the power block. The plant will include two combustion turbines and the plant have a nominal gross electrical generating capacity of 716 MW and a nominal net electrical generating capacity of 602 MW. It is generally planned that the combustion turbines will operate with one turbine operating as a baseload unit and the second as an intermediate load unit. Christian County Generation, in consultation with its customers, would determine when to run the second turbine by assessing the relative revenue from generation of electricity versus production of SNG.

The fuels burned in the combustion turbines will be SNG and natural gas. Although SNG is not a "naturally occurring fluid mixture of hydrocarbons", all SNG produced by plant will meet the criteria of the most stringent potentially relevant regulatory definitions under the NSPS and Acid Rain program, which is the definition for pipeline natural gas under the Acid Rain program, 40 CFR 72.2. Thus, all SNG produced will be between 950 and 1,100 Btu/scf on a higher heating value (HHV) basis. Additionally, the maximum sulfur content of the SNG will not exceed the sulfur content limit in the Acid Rain definition of pipeline natural gas (0.5 grains of total sulfur per 100 scf). To demonstrate the equivalence of SNG and natural gas, Christian County Generation provided a comparison of the anticipated SNG and natural gas specifications for the plant in Table 3-3 of Volume 1 to the Application.[41]

Since the SNG produced by the plant must meet all physical and chemical specifications for commercial or "pipeline" natural gas, natural gas and SNG are used synonymously and are not addressed as different fuels in the BACT analysis for the combustion turbines. Instead, the BACT analysis proposes common emission limits for the combustion turbines that would be applicable to firing of either SNG or pipeline natural gas.

Nitrogen Oxides (NO_X)

Emissions of NO_X are formed during combustion, from nitrogen contained in the atmosphere that is directly introduced into the combustion turbines as combustion air and from nitrogen contained in the fuel. NO_X emissions reductions from combustion turbines exhaust can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Several post-combustion NO_X control technologies are potentially applicable to the proposed facility. These technologies employ various strategies to chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst. The NO_X control technologies identified by Christian County Generation were EM_X/$SCONO_X$, Catalytic Combustion (XONON), SCR, SNCR, Water/Steam Injection, Dry Low-NO_X Combustors (DLN), and good combustion controls. Christian County Generation has proposed the combination of DLN and SCR as BACT for NO_X emissions from the combustion turbines.

[41] The Application shows that the range of heating value of SNG is slightly lower than that of the pipeline natural gas that would be available to the plant.

Goal Line Environmental Technologies developed $SCONO_X$ which can remove both NO_X and CO without supplemental reagent. Now operating as EmeraChem, the current version of the technology is now marketed as EM_X. EM_X uses a platinum-based catalyst coated with potassium carbonate to oxidize CO to CO_2 and NO to NO_2. NO_2 then absorbs onto the catalyst to form potassium nitrite and potassium nitrate. Periodically, the catalyst is regenerated with hydrogen gas that converts the compounds back to potassium carbonate, water and nitrogen. To maintain continuous operation, the system is divided into sections, with one section offline at all times for regeneration. The modules are separated by louvers.

XONON™ replaces the standard combustor in a combustion turbine with a catalytic combustor, lowering the temperature of combustion to reduce NO_X formation. The design of XONON combustors must be customized to the particular model of combustion turbine and, potentially, the operating conditions of the particular application. Accordingly, use of XONON technology for a particular turbine would necessitate a collaborative effort with the manufacturer of the turbine to integrate the hardware into the design of a turbine, assuming that the particular turbine is physically capable of accommodating XONON combustors, which would likely be larger than the standard combustors for the turbine.

SCR uses a chemical reaction with a reagent, typically NH_3, to remove NO_X from a flue gas stream. The reaction between NO_X and the reagent, as they pass through a porous ceramic bed impregnated with catalyst, ideally at a temperature in the range of 575 to 750°F, reduces NO_X back to molecular nitrogen (N_2). Because the turbines at the proposed plant are "combined cycle" turbines equipped with heat recovery steam generators (HRSG), the flue gas from the turbines will be within the necessary temperature range within the HRSG, where the hot exhaust from the turbine is "cooled" to generate steam. In circumstances where SCR can be effectively applied, SCR is considered very effective in controlling NO_X. It is commonly required as BACT for new natural gas-fired combined cycle turbines. This makes SCR a feasible NO_X control technology for the turbines at the proposed plant.

SNCR is another post-combustion control technology using injection of a reagent, either ammonia or urea, similar to SCR but without a catalyst. Because a catalyst is not used, higher temperatures in the range of 1,600 to 2,000 °F are needed for the reagent to selectively react with NO_X to reduce it back to N_2. SNCR is not a feasible control technology because the temperature of the flue gas, as it leaves the turbine, is below the needed minimum temperature. In addition, the control efficiency of SNCR is lower than that of SCR.[42]

Steam or water injection is a combustion control technique that reduces the production of thermal NO_X during combustion. The steam/water acts to lower the peak flame temperature and improve mixing, which result in less production of thermal NO_X. Steam and water injection have been used to reduce NO_X emissions from natural gas fired combustion turbines. These techniques are not as effective in controlling NO_X emissions as SCR, as they can cause combustion "noise" at the level of injection needed to approach the effectiveness of SCR. This noise affects turbine operation, causing flame instability, and vibrations that accelerate wear. Steam and water injection also reduce the fuel efficiency

[42] SNCR does not use a catalyst, depending on the NOx emission rate set for a unit equipped with SNCR, SNCR systems may also pose a concern for ammonia slip from the unit (i.e., emissions of unreacted ammonia). This is because the SNCR process is not as efficient chemically as SCR and comparatively more reagent may be needed to achieve similar levels of NO_X control,

of a turbine, requiring combustion of additional fuel to compensate for the lowered efficiency. This is because of the additional fuel needed to produce the steam or the heat consumed in evaporating the injected water. Lastly, for large utility-scale combustion turbines of the size of those at the proposed plant, when fired with natural gas, similar levels of NO_X control can be achieved with combustor design.

DLN combustor design is a combustion control technology routinely used for natural gas fired combustion turbines. This technology relies on carefully managing the mixing of the natural gas fuel and combustion air prior to firing in the combustor to minimize peak flame temperatures. This technology is most effective for large, utility-scale turbines, in which the combustors are large enough to be designed to both minimize peak flame temperatures and maintain efficient combustion.

Based on information for similar combustion turbines in the Clearinghouse and the permit review results provided by Christian County Generation, the available NO_X control technologies that are demonstrated in practice are SCR, Water/Steam Injection, Dry Low-NO_X Combustors (DLN), and good combustion practices. The most stringent Clearinghouse and permit entries for NO_X and the lowest BACT limit in all of the permit determinations that were reviewed are 2 ppmvd, at 15 percent O_2. All of the facilities identified with the most stringent NO_X BACT limits utilize SCR for control of emissions. Based on this review, the combination of low-NO_X combustion technology and SCR is proposed as the BACT technology for the combustion turbines for NO_X emissions. The proposed BACT limit is 2 ppm at 15 percent oxygen, 3-hr average, applicable only when turbines are operating at or above 60 percent load, i.e., when the temperature of the flue gas will be in the range for the SCR system to be operated effectively to control NO_x emissions.

Carbon Monoxide (CO)

CO emissions are a result of incomplete combustion of fuel in the turbines and their combustion efficiency. The formation of CO occurs in small, localized areas in the burners where oxygen levels cannot support the complete oxidation of hydrocarbons to CO_2.

The available control technologies evaluated are the design of the combustion process and good combustion practices to minimize the formation of CO including maintaining high levels of excess air, and and-on EM_X/$SCONO_X$ and oxidation catalyst systems. Efficient combustors minimize the formation of CO by providing excess oxygen or by mixing the fuel and air more effectively. CO emissions from natural gas combustion can also be decreased via an oxidation reaction in an EM_X/$SCONO_X$ or an oxidation catalyst control system.

While EM_X and $SCONO_X$ are promising, neither have been demonstrated for combustion turbines in the size range of the turbines that would be installed at the proposed plant. Applications to date have been for much smaller combustion turbines, ranging from 5 MW up to 45 MW (with the largest installation proposed for the City of Redding Municipal Electric Plant). Most experience with EM_X/$SCONO_X$ is on units smaller than 25 MW. Since EM_X/$SCONO_X$ technology has not yet been demonstrated on large combustion turbines, like those at the proposed plant, this technology is not considered to be technically feasible.

In oxidation catalyst systems, oxidation of CO is promoted by noble metal-enriched catalysts at elevated temperatures. Under optimum operating conditions, this technology can achieve up to 90 percent reduction efficiency for CO. In practice, efficiency depends on flue gas flow rate, temperature, and composition, notably the CO concentration in the stream being controlled. As applied to fuel combustion emission units, like combustion turbines, significant further oxidation will not take place at the active sites of the catalyst if the flue gas conditions are outside the operating range of the catalyst, as developed and specified by manufacturer's of oxidation catalysts.

Introducing extra air into the combustors in the turbines, raising the level of excess air in the burners, could theoretically reduce CO emissions by raising the amount of oxygen available for more complete oxidation of CO to CO_2. However, the DLN combustors in combustion turbines are designed to be able to provide an appropriate level of excess air in the burners for efficient combustion and efficient turbine operation while minimizing formation of NOx. Introducing extra air into the combustors in an attempt to further lower CO emissions would have the adverse environmental impact of increasing emissions of both NOx and CO_2. In particular, formation of thermal NO_X is minimized with low levels of excess air. Likewise, the air flows in turbines are designed for efficient turbine operation. Introducing extra air into the combustors would depart from the design of the turbines, acting to reduce their fuel efficiency and increase CO_2 emissions. The normal operation of the DLN combustors, with management of the fuel-to-air ratio and good combustion practices, without introduction of extra excess air, will minimize emissions of NO_X and CO_2 while simultaneously also minimizing CO emissions.

Christian County Generation used the procedure recommended in the USEPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual to evaluate the cost effectiveness of using oxidation catalysts on the turbines to reduce CO emissions.[43] In order to evaluate the control efficiency achievable with oxidation catalyst given the already low CO emission rate that will be achievable with combustor design and good combustion practices (i.e., 4.3 ppm, at 15 percent O_2), Christian County Generation reviewed the Clearinghouse for entries for combustion turbines without duct burners that are equipped with oxidation catalyst systems. This search revealed the facilities with CO BACT limits in the range of 0.9 ppm to 2.0 ppm (all at 15 percent O_2), including: 1) Kleen Energy Systems, Middletown, Connecticut, 0.9 ppm, 2) Virginia Electric and Power, Warren County, Virginia, 1.5 ppm, 3) Southern Company/Georgia Power, McDonough Station, Smyrna, Georgia, 1.8 ppm, and 4) Various other facilities with limits of 2 ppm. The permitting and publicly available documents on the company and agency websites for the Kleen Energy Systems, Virginia Electric Power Warren, and Georgia Power McDonough projects indicate that these projects have not yet commenced operation.[44] Since the three facilities with BACT limits lower than 2 ppm have not commenced operation and demonstrated that such lower limits are achievable, it is uncertain whether on-going compliance with a limit that is lower than 2 ppm is feasible or otherwise appropriate for the proposed plant. On the other hand, the CO limit for a number of facilities is 2 ppm. Accordingly, the effectiveness of using a CO catalyst on the proposed

[43] USEPA OAQPS, EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002, EPA/452/B-02-001.

[44] The Kleen Energy Systems project has commenced construction, but the future of the project currently appears to be in jeopardy due to a major accident during construction. (http://www.ct.gov/dpuc/lib/dpuc/kleen/kleenenergyfinalreport.pdf). Virginia Electric and Power's Warren project is currently under construction and is expected to commence operation in Spring 2012. (http://dom.mediaroom.com/index.php?s=43&item=1006) Georgia Power's McDonough project has also started construction but is not expected to be operational until January 2012. (http://www.georgiapower.com/generation/home.asp)

combustion turbines was based on achievement of a CO emission rate of 2 ppm by a new, “state-of-the-art” combustion turbine with oxidation catalyst during normal operation. A CO limit of 2 ppm would represent about 54 percent control compared to the proposed CO BACT limit of 4.3 ppm for the proposed combustion turbines during normal operation. Based on general information from catalyst and turbine vendors, it is reasonable to assume that the control efficiency would be less during the transient conditions of startup and shutdown. For this purpose, Christian County Generation generously assumed that an oxidation catalyst could still achieve 50 percent control efficiency for CO, during startup and shutdown, on average over the duration of these periods (hot/warm/cold starts and shutdowns).[45] This results in on a potential reduction in CO emissions from the proposed turbines from use of oxidation catalyst systems of 144 tons/year. Christian County Generation projected that the average cost-effectiveness associated with this reduction in emissions would be approximately $6,000 per ton of CO removed.

In order to evaluate whether the projected cost impact for CO catalyst systems, $6,000 per ton, would be reasonable and should be considered to be cost effective, a “find lowest emission rate” Clearinghouse search was conducted for permit determinations made over the past 10 years for CO emissions from large natural gas-fired combined cycle combustion turbines (Clearinghouse Process Code 15.210). The results from this search were specifically evaluated for projects that reported control costs for installing oxidation catalyst. Of the 100+ facilities with reported CO BACT limits for natural gas-fired combined cycle combustion turbines identified in this Clearinghouse search, control costs for installing oxidation catalyst were reported for 19 facilities. For these facilities, 8 determinations of excessive cost impacts for oxidation catalyst were made with average control costs ranging from $1,930 to $38,315 per ton of CO removed. The remaining 15 determinations concluded that the costs for installing an oxidation catalyst were warranted with control costs ranging from $1,161 to $9,638 per ton of CO removed. From among these 15 determinations, the only facilities that have borne higher reported $/ton costs to install oxidation catalyst higher than the $6,000/ton cost effectiveness conservatively calculated for the proposed combustion turbines are: 1) the Ivanpah Energy Center in Clark County, Nevada, and 2) the Gila Bend Power Generation Facility southwest of Phoenix in Maricopa County, Arizona.

Based on this detailed review of previous USEPA and state air agency BACT determinations for CO emissions in similar circumstances, the Illinois EPA considers the cost of using an oxidation catalyst to reduce CO emissions from the combustion turbines at the proposed plant to be excessive. In this regard, the CO limit for the Ivanpah Energy Center project is not a BACT limit.

[45] During startup and shutdown of a combustion turbine, the flow rate and temperature of the turbine’s exhaust continuously change. The majority of CO emissions during startup and shutdown occur when turbine load is lowest, when combustion efficiency is also lowest. The flue gas conditions, primarily temperature, at low turbine loads are not ideal for effective CO oxidation in the catalyst system. Without specific catalyst operating data for periods of startup and shutdown, there is considerable uncertainty whether this relatively high level of CO emissions reduction will be achievable during all startup events at the plant and especially during those startups that occur after relatively long periods of turbine downtime (primarily cold and warm starts). Therefore, the cost effectiveness derived from a cost analysis based on this CO control efficiency during startup and shutdown should be conservatively low. The actual CO emissions reductions that Christian County Generation may realize would be lower than anticipated, and as such, the actual control cost on a $/ton basis for use of oxidation catalyst for reducing CO emissions from the proposed combustion turbines may be considerably higher than Christian County Generation estimated in the Application.

Rather, it is a LAER limit, since the Las Vegas area was a CO nonattainment area when the permit determination was made. Cost-impacts may have limited relevance when setting LAER limits for proposed projects. Therefore, the higher costs borne by the Ivanpah project should not be considered relevant to the BACT determination for the proposed plant.

The Gila Bend facility reported a control cost for compliance with a CO BACT limit of 4 ppmv, 15 percent O_2, using oxidation catalyst of $9,638/ton of CO removed. This control cost is based on an assumed control efficiency for the oxidation catalyst of 67 percent, or a nominal uncontrolled emission rate of 12 ppm CO.[46] Given the difference in the level of CO emission reduction to be achieved with oxidation catalyst at Gila Bend, 8 ppm (12 ppm uncontrolled to 4 ppm controlled) and the reduction that would be achieved with oxidation catalyst at the proposed plant, 2.3 ppm (4.3 ppm uncontrolled to 2 ppm controlled), the reported cost-effectiveness value for Gila Bend should not be used a reference point for comparison to the cost-effectiveness value determined for the proposed plant.[47] Rather, it merely indicates that oxidation catalyst systems may be cost-effective if the uncontrolled CO emissions of a turbine, or a turbine and associated duct burner, as is the case at Gila Bend, are high. In such circumstances, oxidation catalysts system would provide a substantial reduction in CO emissions. However, these are not the circumstances of the proposed combustion turbines, for which good combustion practices would now be effective in minimizing CO emissions. Moreover, the determination for Gila Bend was made nearly ten years ago and is not consistent with more recent determinations which have concluded that oxidation catalyst are not cost effective at significantly lower $/ton control costs. It is also noteworthy the CO BACT limit for Gila Bend with oxidation catalysts (4 ppm at 15 percent O_2) is only slightly lower than the proposed CO BACT limit for the proposed plant without oxidation catalyst (4.3 ppm at 15 percent O_2). As these limits apply to CO, the difference in these limits is so small that these limits should be considered equivalent.[48, 49, 50]

---

[46] Technical Support Document, Gila Bend Power Generation Project, Prevention of Significant Deterioration, Title IV, and Title V Permit Number V00-001, November 12, 2001

[47] As the oxidation catalyst systems at Gila Bend would provide over three times more reduction in CO emissions than would be achieved with the proposed turbines, the basic arithmetic of cost-effectiveness calculations would indicate that the catalyst systems would be significantly more cost-effectiveness than such systems at the proposed plant, if the magnitude of the two projects is similar, which is the case. In other words, the costs of the systems should be similar in magnitude but the systems at Gila Bend should be about three times more cost-effective as the reduction in CO emissions that is provided is three times larger.

[48] In addition, from a compliance perspective, a CO CEMS reading as high as 4.49 ppm for the Gila Bend facility might be considered compliant after applying rounding while the same reading would be a violation of the proposed CO BACT limit for the proposed plant.

[49] The CO limit for the Ivanpah project is also 4 ppm at 15 percent O_2, and is also essentially equivalent to the CO BACT limit that is proposed for the proposed combustion turbines.

[50] In addition, one can also speculate that another potential reason that the facility may have been willing or required to incur the relatively high cost to use oxidation catalyst may have been Maricopa County's Rule 240, which requires an evaluation of potential impacts on the Phoenix ozone nonattainment area to be conducted for all projects within 50 kilometers of the of the nonattainment area. (Maricopa County's Rule 240.308.1(e)(2) was in effect at the time the Gila Bend determination was submitted to the Clearinghouse.) As part of this analysis, Arizona Department of Environmental Quality (ADEQ) commissioned an ozone modeling study that included the permitted emissions from the Gila Bend facility with oxidation catalyst. If oxidation catalyst was not applied to reduce emissions of VOC by 50 percent, the results of the ozone modeling study may not have been favorable. Potential adverse impacts predicted by the

With use of oxidation catalyst technology eliminated due to associated cost impacts, use of good combustion practices is proposed as BACT, to comply with a proposed BACT limit of 4.3 ppm, at 15 percent O_2, 3-hr average, applicable only during periods other than startup or shutdown, i.e., operation of a turbine at a load of 60 percent or above. The Clearinghouse search results for CO emissions from combustion turbines were further reviewed to identify any facilities that appear to use good combustion practices to comply with lower limits than that proposed for the plant. This search did not identify any facilities that use good combustion practice as the selected BACT control technology that are actually subject to CO limits that are lower than 4 ppm, 15 percent O_2.[51] As shown by the Clearinghouse search, the proposed CO BACT limit is supported by recent permits and applications for projects involving natural gas-fired combustion turbines.

Volatile Organic Matter (VOM)

Since VOM is also a product of incomplete combustion, the available control options for VOM emissions from the turbines are the same as those for CO. As such, cost effectiveness of oxidation catalysts was evaluated using similar cost assumptions to those used for CO. Based on a 50 percent VOM control efficiency for oxidation catalyst during all periods of operation, the further reduction in VOM emissions from the two combustion turbines would be 18 tons/year, at an average control cost of approximately $48,000 per ton, removed. Illinois EPA does not consider this cost to be reasonable.

With oxidation catalyst eliminated, good combustion practices are proposed as BACT for VOM. The proposed BACT limit is 0.0013 lb/mmBtu, 3-hr average, applicable for periods other than startup or shutdown, i.e., operation of the turbine at loads of 60 percent or above. As shown in the Clearinghouse searches provided by Christian County Generation, the proposed VOM BACT limit is supported by recent permits and applications for projects involving natural gas-fired combustion turbines.

Particulate Matter (PM)

---

modeling based on the uncontrolled VOC emissions from the turbines may have required Gila Bend to use an oxidation catalyst to satisfy Rule 240.

[51] The review did identify three facilities whose CO limits are erroneously identified as being below 4 ppm: 1) Oglethorpe Power Wansley Combined Cycle Energy Facility, 2) LSP Batesville Generation, and 3) Competitive Power Venture (CPV) Cunningham Creek.

The CO BACT limit in the Clearinghouse for Oglethorpe Wansley, 2.0 ppm, at 15 percent O_2, was incorrectly entered based on a review of the actual PSD permit issued by the Georgia Environmental Protection Division (EPD). Georgia EPD, ***Part 70 Operating Permit Amendment (Permit No. 4911-149-0001-V-01-2) for Wansley Steam-Electric Generating Plant***, July 28, 2000. The correct CO BACT limit for the facility is 0.061 lb/mmBtu, which is equivalent to about 30 ppm at 15 percent O_2.

Similarly, the CO limit for LSP Batesville was incorrectly entered as 2.5 ppm at 15 percent O_2 when it should have been entered as 25 ppm.

Mississippi Department of Environmental Quality, ***State of Mississippi Air Pollution Control Title V Permit for LSP Energy, LLP Batesville Generating Facility*** (Permit No. 2100-00054), August 18, 2003.

Finally, the CPV project was never constructed and has been abandoned. The proposed CO BACT limit of 10 lb/hr at or above 70 percent load (equivalent to 3.1 ppm at 15 percent O_2) was never demonstrated as achievable. County of Fluvanna, Staff Report, Revocation of Special Use Permit 01:07 for Competitive Power Ventures, Inc., June 25, 2008. (http://www.co.fluvanna.va.us/planning/meeting/2008/June%2008/SUP%2001-07.pdf)

Emissions of filterable particulate from the turbines are formed by impurities in the fuel and from incomplete combustion. Condensable particulate is attributable primarily to the formation of condensable sulfates and organic compounds as combustion byproducts. The most common particulate control method demonstrated for natural gas-fired combustion turbines is the use of low ash and low sulfur fuel in conjunction with good combustion practices. No add-on control technologies are listed in the Clearinghouse. Add-on controls, such as electrostatic precipitators, baghouses, or wet scrubbers, have never been applied to commercial natural gas-fired combustion turbines. Therefore, these add-on control technology options are not considered to be available or applicable for reducing PM emissions from combustion turbines.

Based on the use of SNG and natural gas as the only fuels for the turbines and good combustion practices, a BACT limit of 0.0065 lb/mmBtu a 3-hr average, is proposed for PM, PM_{10}, and $PM_{2.5}$ emissions from the turbines. As shown in the Clearinghouse searches provided by Christian County Generation, this proposed BACT limit is supported by recent permits and applications for natural gas-fired combustion turbines.

Sulfur Dioxide (SO_2)

Emissions of SO_2 from the turbines are a result of sulfur in the fuel. The only available controls for SO_2 are flue gas desulfurization (FGD) scrubber technology and combustion of low sulfur fuels. There have been no applications of FGD scrubbers on natural gas-fired combustion turbines. This is due to the low levels of emissions, which reflect very low concentration of SO_2 in the exhaust (i.e., less than 0.2 ppm at 15 percent O_2). Due to these low SO_2 concentrations, FGD technology would not provide any measureable emission reduction and is, therefore, technically infeasible.

Based on SNG and natural gas being the only fuels for the turbines, a SO_2 BACT limit in terms of fuel composition, 0.25 gr sulfur/100 scf of fuel, is proposed. As shown in the Clearinghouse searches provided by Christian County Generation, this proposed limit is supported by recent permits and applications for natural gas-fired combustion turbines.

Carbon Dioxide (CO_2)

Christian County Generation evaluated carbon capture and sequestration (CCS), selection of fuel efficient turbine design, fuel selection, and good combustion/operating practices as available control options for reducing CO_2 emissions from the turbines. Despite the noted challenges discussed above which render CCS an infeasible technology for the gasification block, Christian County Generation chose to also evaluate the feasibility of post-combustion capture technologies applied to natural gas-fired combustion turbines.

Post-combustion carbon capture could be accomplished with low pressure scrubbing of CO_2 from the combustion turbines exhaust stream with either solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale and solid sorbents and membranes are only in the research and development phase. Although carbon capture is an established process in some industry sectors (i.e., when applied to acid gas recovery units in the gasification and chemicals industries), it has not been commercially demonstrated in the power generation sector in baseload or full stream applications. Post combustion capture has only been demonstrated on small slip streams for limited periods.

Six projects developed since 1978 (AEP Mountaineer, First Energy R.E. Burger, AES Warrior Run, AES Shady Point, IMC Chemicals, and WE Energy Pleasant Prairie) have demonstrated small scale post combustion carbon capture on slip streams diverted from the exhausts of coal-fired boilers. Three other larger scale CCS demonstration projects on coal-fired boilers (Basin Electric in North Dakota, NRG Energy in Texas, and AEP in West Virginia) have been proposed through the USDOE's Clean Coal Power Initiative; however, none of these facilities are operating, and, in fact, they have not yet been fully designed or constructed. In addition to these post combustion capture applications for coal-fired boilers, Northeast Energy Associates conducted CO_2 capture to produce 320 to 350 tpd CO_2 using a Fluor Econamine FGSM scrubber on 15 percent of the flue gas from its 320 MW natural gas combined cycle facility in Bellingham, Massachusetts from 1991 to 2005.[52]

Although these projects indicate small-scale CO_2 capture is technically feasible for coal-fired boilers and natural gas combined cycle turbines, it does not support the availability of full-scale CO_2 capture on the 602 MW combined cycle power block at the plant, which would be more than an order of magnitude larger than any of these CO_2 capture projects. Furthermore, small scale projects that capture CO_2 to produce a commodity for soda ash production and for the food and beverage industry are not applicable to the plant, since the markets for CO_2 in the Midwest can be readily met by grain ethanol plants. Finally, while CO_2 capture technology may be available, the obstacle to CCS is sequestration. Given the limited deployment of only slipstream/demonstration applications of CO_2 capture and issues associated with carbon sequestration discussed previously in CO_2 BACT analysis for the AGR Unit CO_2 vent, the Illinois EPA does not consider CCS to be a technically feasible technology for the combustion turbines.

With CCS eliminated, selecting the most efficient combustion turbines design was evaluated as a possible option for CO_2 emissions from the combustion turbines. In general, larger turbines, which operate at higher temperatures, have the highest efficiencies. These larger turbines include F-Class turbines (as proposed by Christian County Generation), a G-class and H-class turbines all of which are possible options. With the increasing alphabetical class, the capacity and the firing temperature of the turbine increase, along with the steady state combustion efficiency and associated energy efficiency. As compared to F-class turbines, G- and H-class turbines typically achieve slightly higher efficiencies. This is due to more efficient cooling systems and metallurgical advances that enable the turbines to fire at higher temperatures, thereby increasing efficiency and reducing emissions per unit of fuel combusted (lowering fuel consumption per MW output). However, G- and H-class turbines were, eliminated from consideration for the proposed plant due to various project requirements which necessitated use of an F-class turbine.

Christian County Generation's target name plate rating for the gross electricity output combined cycle power block with its 2 x 1 configuration[53] is

[52] International Energy Agency, CCS Research and Development Database: Bellingham Cogeneration Facility(http://www.ieaghg.org/index.php?/RDD-Database.html)

[53] The characterization of the power block as "2 x 1" identifies the configuration of the power block, with two separate combustion turbines (<u>2</u> x 1) and one shared steam turbine generator (2 x <u>1</u>). Other configurations are also possible for combined cycle power facilities. For example, 2 x 2 would mean that a facility has two combustion turbines, each with its own, dedicated steam turbine generator. 1 x 1 would mean that the facility only has a single combustion turbine and steam turbine generator.

greater than 500 MW but less than a rating that would produce more power than the plant could reasonably be expected to sell. With regard to larger G-class turbines, the ISO rating in a 1 x 1 combined cycle configuration is a nominal 404 MW (using the Mitsubishi Heavy Industries, or MHI, 501G model as the basis). Even with heavy supplemental firing/process steam, the output would be short of the project design requirement of 500 MW using a single G-class turbine. Therefore, a 2 x 1 configuration would then be needed. A 2 x 1 configuration with G-class turbines would have an ISO output rating of a nominal 810 MW (MHI 501G) and with input of additional process steam, the output could approach 900 MW. In this case, although the 2 x 1 G-class combined cycle would meet minimum plant output requirements as well as plant electric loads at partial load operations, but the excess capacity and associated capital costs would be inconsistent with the scale of the proposed plant and project economics, and be inconsistent with the design objectives for the plant. As a first of its kind facility, Christian County Generation has prudently designed and would develop the plant to meet certain capacity targets that balance the capital cost of the plant and the available revenues from supplying power to the grid and natural gas to the pipeline, which both will be dictated by local market conditions expected to be present after the plant commences operation. In addition to the overall capacity, market dispatch models for the power block suggest the plant will be run in multiple operating scenarios and at various loads. The combustion turbines will typically operate with one turbine in baseload mode and one in an intermediate load (which will involve cycling the turbine and running it at intermediate loads). To date, the larger G-class turbines are designed for pure baseload operations. There are significant concerns with the ability of G-class turbines to cycle frequently given the design of these turbines.

Each of the limiting factors discussed above with respect to G-class turbines is equally applicable for H-class turbines. There are H-class turbines that generate electricity at 50 cycles per second (Hertz or Hz) operating overseas. However, the electrical system in the United States is 60 Hz. The key difference between 50 and 60 Hz generating systems is that in 60 Hz service turbines must rotate 20 percent faster. A different generator cannot be installed with a turbine designed and developed for operation at 50 Hz to enable the turbine to be used for a 60 Hz electrical system. H-class turbines designed for 60 Hz generation have only recently been permitted for use in power plants in the United States. For the only 60 Hz projects identified (FP&L plants in Riviera Beach and Cape Canaveral Florida), the turbines would be in a baseload capacity, replacing coal-fired units at the plants.[54] [55] As previously discussed, the combustion turbines at the proposed plant will operate in both baseload and intermediate load service. The Statement of Basis issued by the Bay Area Air Quality Management District with the draft PSD Permit for the Russell City Energy Center in August 2009 made the same conclusions with respect to the technical infeasibility of G- and H-class turbines for a natural gas combined cycle plant similar in size to the proposed plant.[56]

---

[54] Florida Department of Environmental Protection (Florida DEP), NSR/PSD Construction Permits – FPL Riviera, Palm Beach County (http://www.dep.state.fl.us/air/emission/construction/fplriveria.htm)

[55] Florida DEP, NSR/PSD Construction Permits – FPL Cape Canaveral, Brevard County (http://www.dep.state.fl.us/Air/emission/construction/fplcanaveral.htm)

[56] BAAQMD, Additional Statement of Basis, Russell City Energy Center, August 3, 2009, available at http://www.baaqmd.gov/Divisions/Engineering/Public-Notices-on-Permits/2009/080309-15487/Russell-City-Energy-Center/15487-SB-080309/Additional-Statement-of-Basis-for-the-Proposed-Permit.aspx

In Table 7-2 of Volume 1 to the Application, Christian County Generation provided a comparison of the relative heat rates and efficiencies for F-class combustion turbines from leading manufacturers. Although there is very little difference in the heat rates and efficiencies for new F-class combustion turbines, the GE 7FA.05 turbine is slightly more efficient than the Siemens SGT6-5000F turbine selected for the plant. This difference should be attributed to slight differences in the approach for providing efficiency data by GE and Siemens or the slightly larger size of the GE turbines, not to any particular technology advances to improve efficiency. When viewed in terms of the maximum annual fuel heat input and potential CO_2 emissions, the two turbines are nearly equivalent.[57] Illinois EPA considers the efficiency decrease from selecting the Siemens turbines to be insignificant and, therefore, GE and Siemens turbines should be considered equivalent from a BACT perspective in the remaining steps of the BACT analysis.

Based on the selection of state-of-the-art, high efficiency F-class combustion turbines using good combustion/operating practices, the proposed CO_2 BACT limit for the turbines is 1,201 lb CO_2/MW-hr, 12-month rolling average basis (gross at the turbine generator) for the two turbines combined, for normal operation of the turbines, i.e., excluding periods of startup and shutdown, when a turbine is operating at less than 60 percent load. Separate CO_2 BACT limits are proposed for startup and shutdown, all on a per-event basis, i.e., 291,685 lb/cold startup, 72,860 lb/warm startup, 37,180 lb/hot startup, and 30,140 lb/shutdown. The separate limits for startup and shutdown are appropriate because the generally applicable BACT limit would be expressed in terms of electrical output. During a portion of startup and shutdown, the turbines do not actually have any electrical output. The total amount of output during these events also will not be fixed but will vary, at a minimum based on the particular type of event.

To determine whether or not the proposed limits for GHG emission for the combustion turbines constitute BACT, GHG BACT determinations and permit applications for the following recently proposed natural gas combined cycle plants or projects were considered: 1) Russell City Energy Center (RCEC), 2) Cricket Valley Energy Center, 3) Deer Park Energy Center, 4) Lower Colorado River Authority (LCRA), Ferguson Plant, 5) Mackinaw Power, Effingham Plant, and 6) PacifiCorp, Lake Side Plant. The principal strategy used to establish GHG BACT limits for the combined cycle turbines in these projects, as recommended by USEPA in comment letters on the permit determinations, is to propose limits on the heat rate (e.g., Btu of fuel combusted per net MW-hr of power produced by the plant) or the net combined cycle power output-based CO_2e emissions (e.g., pounds of CO_2e emissions per net MW-hr of power produced). These metrics for measuring efficiency and CO_2 emissions from a conventional natural gas combined cycle (NGCC) power plant depend on the net electrical output of the plant, which is a function of the gross electrical output from the combustion turbine generator(s), the steam turbine generator(s), and the amount of electricity consumed within the plant, also referred to as the parasitic load. With a gasification block, which consumes a larger amount of electric power

[57] In fact, because the Siemens turbines are slightly smaller, they will consume less fuel and their potential CO_2 emissions on an annual basis will be less than the GE turbines despite the slightly higher efficiency of the GE turbines.
Assuming continuous operation, the GE 7FA.05 turbine has an annual fuel heat input of 1,640,000,000 mmBtu/yr and potential CO_2 emissions of 901,926 tpy, based on a CO_2 emission factor of 110 lb/mmBtu, from AP-42, Chapter 3.1. The Siemens SGT6-5000F turbine has an annual fuel heat input of 1,630,000,000 mmBtu/yr and potential CO_2 emissions of 897,420 tpy. The percent difference in annual fuel heat input and CO_2 emissions for these two turbines is less than 0.7 percent.

than the power-users at a conventional NGCC power plant, the parasitic load at the proposed plant is larger than the parasitic load at the proposed NGCC plants with recent GHG BACT determinations. Therefore, the combined cycle heat rates and combined cycle power output-based GHG emission limits proposed for these NGCC facilities cannot be compared directly to the proposed GHG BACT limit for the combustion turbines at the proposed plant without first converting the GHG BACT limits into a gross combustion turbine power output basis. As such, in the following discussions of the proposed GHG BACT limits for each of the six NGCC projects identified previously, data presented in the permit or permit applications for these projects has been used to derive an equivalent GHG emission rate from the combustion turbines expressed in the same basis as the proposed GHG BACT limit for the proposed plant.

The Russell City Energy Center (RCEC) in Haywood, California, permitted by the Bay Area Air Quality Management District (BAAQMD) in February 2010, would have two Siemens-Westinghouse 501F combustion turbines, with capability for supplemental duct firing for the HRSGs, with a nominal capacity of 600 MW_{net} for sale to the grid. RCEC accepted hourly, daily, and annual CO_2e-based emission limits and a combined cycle heat rate limit in its PSD permit as voluntary BACT limits for GHG.[58] For comparison purposes, the hourly CO_2e emission limit (533,500 lb CO_2e/hr) is converted into a lb/MW-hr limit based on the combined gross power output rating of the two combustion turbine generators (total 400 $MW_{nominal}$).[59] Based on this method for expressing the RCEC limit, the proposed CO_2 BACT limit for the proposed plant (1,201 lb CO_2/MW-hr) is more stringent than the voluntary CO_2 BACT limit accepted by the RCEC (1,334 lb CO_2e/MW-hr).[60]

Cricket Valley Energy (CVE) is proposing to construct a 1,000 $MW_{nominal}$ NGCC power plant in Dover, New York. The plant will have three F-class combustion turbine (GE Model 7FA.05) each with a HRSG with supplemental duct firing and its own steam turbine generator.[61] The New York State Department of Environmental Conservation (NYSDEC) issued a draft PSD permit for the project on May 25, 2011, which does not contain any GHG BACT limits.[62] However, CVE did include a GHG BACT analysis in the Draft Environmental Impact Statement (DEIS) for the project.[63] In comments on the draft PSD permit, USEPA requested that NYSDEC include a combined cycle heat rate and annual CO_2e limit in the permit consistent with the GHG BACT analysis submitted by CVE with the DEIS.[64] Each of the three combustion turbines proposed for CVE would have a gross power output capacity of 211 MW and the annual potential CO_2 emissions from the three combustion turbines combined are 3,576,943 tons/year. This results in an output based CO_2 emissions performance for the turbines of 1,290 lb CO_2/MW-hr. When

---

[58] BAAQMD, Prevention of Significant Deterioration Permit Issued Pursuant to the Requirements of 40 CFR §52.21 (Permit Application No. 15487), February 3, 2010.
[59] BAAQMD, Statement of Basis for Draft Amended "Prevention of Significant Deterioration" Permit for Russell Energy Center, December 8, 2008.
[60] Although the RCEC limit is expressed on a CO_2e basis and includes emissions of methane and N_2O from the combustion turbines at the site, adding methane and N_2O emissions to the CO_2 limit for the TEC to convert it to a CO_2e basis is not expected to increase the numerical value of the limit by more than 1 percent.
[61] Cricket Valley Energy, Application for Prevention of Significant Deterioration and Part 201 Air Permit, March 2010.
[62] NYSDEC, Permit Under the Environmental Conservation Law (ECL) Article 19: Air Pollution Control – Air State Facility Permit for Cricket Valley Energy, LLC (Permit ID: 3-1326-00275/00004), May 25, 2011.
[63] Cricket Valley Energy, Draft Environmental Impact Statement, April 2011.
[64] USEPA Region 2, EPA Comments on the Draft State Prevention of Significant Deterioration of Air Quality (PSD) Permit for the Cricket Valley Energy Center, Dover, New York, July 29, 2011.

expressed on a gross combustion turbine power output basis, the CO_2 emissions from the combustion turbines for CVE would be somewhat higher than the proposed GHG BACT limit for the turbines at the proposed plant (1,201 lb CO_2/MW-hr).

The owner of the Deer Park Energy Center, Calpine, submitted a PSD permit application (which only addressed GHG emissions) to USEPA Region 6 for the proposed construction of a fifth combustion turbine at the existing Deer Park power plant in Deer Park, Texas.[65] In the GHG BACT portion of the application, Calpine proposed a combined cycle heat rate limit for the generating unit of 7,730 Btu/kW-hr (HHV) which is equivalent to 0.460 ton CO_2e/MW-hr (net basis). The new Siemens 501F combustion turbine proposed for the plant has a gross power output rating of 180 MW and the annual potential CO_2 emissions from the turbine (without duct firing) presented in the application is 945,933 tpy, which gives a gross power output-based CO_2 emission rate of 1,200 lb/MW-hr. This CO_2 emissions performance for the Deer Park turbine is nearly identical to the proposed GHG BACT limit for the proposed plant.

The Lower Colorado River Authority (LCRA) submitted a PSD permit application to the Texas Commission on Environmental Quality (TCEQ) on October 29, 2010 for the proposed installation of two combustion turbines at the LCRA's existing Ferguson Power Plant in Llano County, Texas.[66] The new turbines would replace the existing 435 MW steam boiler generating unit at this plant. LCRA provided CO_2 emissions and combustion turbine gross power output data for both the GE 7FA.04 and Siemens SGT6-5000F(4) combustion turbine models being considered for the project over a range of potential operating conditions. No comparison of the CO_2 emissions performance of the Siemens turbines is necessary since Christian County Generation plans to install the same Siemens model as LCRA. The CO_2 emissions performance of the GE 7FA.04 turbines ranges from 1,152 to 1,609 lb/MW-hr depending on the operating load, ambient temperature, and evaporative cooler operating mode used for the emission calculations. Across the entire range of turbine loads and ambient conditions used by Siemens in the CO_2 emission calculations for the proposed plant, the CO_2 emissions performance of the turbines ranges from 1,064 lb/MW-hr to 1,500 lb/MW-hr. Therefore, the CO_2 emissions performance of the combustion turbines at the proposed plant is similar or superior to the expected emissions performance of the LCRA turbines when viewed on a gross combustion turbine power output basis.

On December 3, 2010, Mackinaw Power submitted a GHG BACT analysis to the Georgia Environmental Protection Division for a proposed project at its existing Effingham power plant.[67] The project involves the addition of two GE 7FA combustion turbines, in a 2 x 1 configuration, capable of producing 668 $MW_{nominal}$ of electrical output (net basis). While Mackinaw Power did not propose any emission limits in the GHG BACT analysis, it did provide CO_2 emissions data that can be compared against the proposed GHG BACT limit for the proposed plant. The CO_2 emission rate for the two combustion planned for the Mackinaw Power project without duct firing in the HRSGs is 814.2 lb CO_2/MW-hr when producing 542.6 MW_{gross} (173.8 MW_{gross} from each combustion turbine and 195 MW_{gross} from the steam turbine). This combined cycle output-based CO_2 emission rate can be converted to a combustion turbine output-based emission rate by multiplying

[65] Deer Park Energy Center, LLC, Prevention of Significant Deterioration Greenhouse Gas Permit Application for an Additional Combined Cycle Cogeneration Unit at the Deer Park Energy Center, Harris County, Texas, September 1, 2011.
[66] LCRA, Application for an Air Quality Permit for Two Combined Cycle Electric Generating Units at the Thomas C. Ferguson Power Plant Llano County, Texas, October 29, 2010.
[67] Mackinaw Power submitted its GHG BACT analysis in response to a comment letter received from the Georgia Environmental Protection Division (EPD).

the combined cycle emission rate (814.2 lb CO_2/MW-hr) by the ratio of the combined cycle electrical output to the electrical output of just the combustion turbines [542.6 MWgross/(173.8 MW_{gross} x 2)], which gives a gross combustion turbine power output-based CO_2 emission rate of 1,271 lb/MW-hr, comparable to the proposed limit of 1,201 lb/MW-hr for the proposed plant. On May 4, 2011, PacifiCorp was issued a final PSD permit for the addition of a second combined cycle power block at its existing Lake Side power plant in Utah County, Utah.[68] The GHG BACT limit for the combined cycle power block in the permit is 950 lb/MW-hr (gross basis) on a 12-month rolling average basis, which is significantly higher than the combined cycle power output-based CO_2 emission rates from any of the other similar facilities evaluated. The gross combustion turbine power output-based CO_2 emission limit established as BACT for the combustion turbines at the proposed plant is nearly equal to the limit set for Lake Side without even considering the power output from the steam turbine. Thus, the proposed GHG BACT limit for the proposed plant is more stringent than the Lake Side limit without even converting the Lake Side limit to an equivalent limit in terms of combustion turbine power output.

As shown by the above analysis of recent GHG BACT determinations for NGCC power plants, the proposed GHG BACT limit for the combustion turbines at the proposed plant is supported by recent permits and applications for similar facilities.

Greenhouse Gases (Methane and Nitrous Oxide (N_2O))

The only available options for reducing methane emissions from the combustion turbines are selection of a modern, high efficiency F-class combustion turbine and good combustion/operating practices to minimize unburned fuel (operating in a lean pre-mix mode when at steady state). Although oxidation catalysts were identified in the CO and VOM BACT analyses as an available control option, they are not considered available for reducing methane emissions. Unlike CO oxidation catalysts which typically operate at relatively low temperatures, low residence times, high space velocity (flow per unit of volume catalyst), and low precious metal catalyst loadings, oxidizing the very low concentrations of methane present in the exhaust of the turbines (approximately 2 ppmv) would require much higher temperatures, residence times, and catalyst loadings than those offered commercially for CO oxidation catalysts. For these reasons, catalyst providers do not offer products for reducing methane emissions from gas-fired combustion turbines.

With oxidation catalysts eliminated, Christian County Generation proposed the installation of new, high efficiency F-class combustion turbines and good combustion/operating practices as BACT technology for methane emissions from the turbines. The annual potential methane emissions from the combustion turbines are included in the proposed annual CO_2e-based GHG BACT limit of 2,307,110 tons of CO_2e/year for the power block. A separate CO_2e-based GHG BACT limit was established for the power block to support the power output-based emission limit discussed previously.

In the Application, Christian County Generation identified a potential tradeoff between NO_X and N_2O emissions from the combustion turbines whereby combustion control measures typically applied to reduce peak flame temperature and NO_X

[68] Utah Department of Environmental Quality Division of Air Quality, Approval Order: Installation of Lake Side Block #2 at PacifiCorp's Lake Side Power Plant, Project Number: N013031-0010, May 4, 2011.

emissions may actually increase N_2O emissions. However, it is not considered appropriate to manipulate the DLN combustors in the turbines to reduce N_2O emissions due to the possibility of concurrently increasing NO_X emissions. In cases where criteria pollutant emissions could increase due to the implementation of a GHG control measure, it is important to consider the relative air quality benefits of reducing GHG emissions in comparison to the potential adverse air quality impacts posed by simultaneously increasing emissions of a criteria pollutant. The projected N_2O emissions of the turbines are relatively small compared to NO_X emissions (56.4 versus 169.0 tons/year), so the potential benefit of using combustion controls to reduce N_2O emissions from the combustion turbines is limited. In addition, the adoption of a new 1-hour NO_2 NAAQS indicates USEPA's continued concern over direct short-term health and welfare effects from NO_2 exposure. Therefore, good combustion practice for the purposes of minimizing N_2O formation was eliminated from consideration in the BACT analysis on the basis of adverse environmental impacts. Similar to the BACT determination for methane, a separate limit for N_2O emissions is not proposed. Rather, N_2O emissions from the combustion turbines are addressed in the annual CO_2e-based limit for the power block.

Startup, Shutdown and Malfunction

The BACT emission limits for NO_X, CO, VOM, and CO_2 discussed above are intended to apply only during normal operation of the turbines. Alternative work practice requirements are proposed for periods of startup, shutdown, and malfunction (refer to Draft Condition 4.2.5-2). A number of factors preclude imposition of turbines BACT limits for these pollutants expressed in ppm or lb/mmBtu during such periods. These include: 1) transient operating conditions during SSM events, (2) exhaust gas temperatures outside of the effective range of the controls, 3) the stringent levels of control that are normally required of the units, and 4) the required use of low-NO_X burners and SCR for the turbines, which need appropriate operating conditions in the flue gas from turbines for effective control of emissions. An alternative approach to these periods is needed that recognizes the inherent technological limits of combined cycle combustion turbines during periods of startup, shutdown and malfunction, as compared to periods of normal operation.

The required BACT work practices during periods of startup, shutdown and malfunction are intended to assure that appropriate measures are taken during such periods to minimize emissions. For this purpose, the draft permit establishes both certain basic measures that must be used as well as a general approach to minimization of emissions through formal operating and maintenance procedures, which may be refined based on actual operating experience at the plant. One key element is that SNG that is used as fuel in the combustion turbines must have been processed by the cleanup train. "Off-specification" syngas, as would be produced during startup or shutdown of the gasifiers and associated cleanup train or during a malfunction of the cleanup trains must be safely disposed of by flaring, rather than by use as fuel. To generate electricity during periods when "off specification" syngas is being produced, Christian County Generation would have to fire natural gas in the turbines.

The BACT limits for periods of startup and shutdown which are expressed in pounds per event, are also 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.

Part 4: BACT Discussion for Material Handling and Processing

1. General Material Handling (Particulate Matter)

Christian County Generation has proposed a variety of measures, including use of baghouses and implementation of work practices to control both so-called "stack" and "fugitive" PM 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.

The PM BACT level control option for material handling, with the exception of the gasifier coal bunker vents, three coal transfer points, and the inactive coal storage pile, is enclosure to prevent visible emissions and aspiration to a control device such as a fabric filter or baghouse capable of achieving an exit PM grain loading of 0.005 gr/dscf. Filtration is generally considered the most effective active control technology for control of dust from material handling operations at power plants. 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. Based on the expected exit grain loading of the filter or baghouse and the expected particle size distribution for the controlled PM emissions, hourly and annual PM_{10}, and $PM_{2.5}$ BACT limits are also proposed for each of material handling units in draft Condition 4.3.2(e), which references Attachment 1, Table I of the draft permit.

For the gasifier coal bunker vents, the PM BACT level control option is enclosure to prevent visible emissions and aspiration to a control device such as a fabric filter or baghouse capable of achieving an exit PM grain loading of 0.008 gr/dscf. High pressure CO_2 carrier gas from the lock hoppers is intermittently discharged through these vents, so the forced draft exhaust during these events produces a higher exit grain loading than for the other induced draft baghouses at the plant. Hourly and annual PM_{10}, and $PM_{2.5}$ BACT limits are also proposed for the filters on the coal bunker vents, by reference to Attachment 1, Table II of the draft permit.

For the coal transfer points and storage pile designated in draft Condition 4.3.2(d), the BACT level control option for reducing fugitive PM emissions is wet dust suppression that achieves between 50 and 90 percent nominal control depending on the emission source and type of dust suppression measures implemented. For the coal transfer points into the active storage dome, onto the inactive pile conveyor, or onto the inactive pile, water sprays shall be applied to achieve a 50 percent nominal control efficiency. For the inactive pile, chemical suppressants would be sprayed on the pile to achieve a 90 percent nominal control efficiency. Finally, for the coal transfer point from the inactive pile reclaimer onto the conveyor feeding the plant, no additional controls are necessary beyond the inherent chemical latency of the sprays on the pile which is capable of achieving a 85 percent nominal control efficiency. Given the size of the plant property and location in an agricultural area, the BACT determination need not require storage of all bulk dry materials in buildings or silos. This approach requires very effective control of PM emissions related to coal transfer points and storage piles as control of fugitive emissions is addressed by a minimum performance specification for the overall effectiveness of control measures.

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/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.

2. Coal Dryers

The proposed plant will have two gas-fired direct thermal dryers for coal. The dryers will use the heated air from combustion of fuel in direct contact with wet coal to reduce the coal’s moisture content. Milled and dried coal will be transported to a collection device for subsequent pneumatic transport to the gasifier feed system. The collection device, a baghouse, is part of the coal drying process unit. Once collected in the baghouse, the milled and dried coal will be conveyed to storage. The combustion exhaust from the two dryers which contains trace amounts of filterable PM (in the form of coal dust) from the coal collection process will be combined and vented through a single stack.

Christian County Generation considered various control technologies for the coal dryers including: 1) cyclones, baghouses, and venturi scrubbers for particulate control, 2) oxidation catalyst and good design and operating practices for CO and VOM control, 3) good operating practices for condensable PM control, 4) SCR, SNCR, and LNB for NO_X control, and 5) use of low sulfur natural gas and SNG fuel for SO_2 control.

Particulate Matter

The particulate matter emissions from the coal dryers contain both filterable and condensable PM. The majority of filterable PM is generated from the coal and transport of milled coal to the product collection baghouse. A small amount of filterable PM is also formed from natural gas combustion in the dryer burners. The source of condensable PM emissions in the dryer exhaust is natural gas combustion in the dryer burners. The following BACT summary addresses emissions of both filterable and condensable PM.

Cyclones or centrifugal collectors are part of the group of air pollution controls often referred to as "precleaners," because they are used to reduce the inlet loading of particulate matter to downstream collection devices by removing larger, abrasive particles. Cyclones are used to control PM, and primarily size fractions of PM greater than PM_{10}. However, there are high efficiency cyclones designed to effectively remove PM less than PM_{10} and $PM_{2.5}$. Centrifugal collectors are part of the inherent process design for the plant's coal milling and drying system. The coal/combustion gas mixture from the mill grinding area flows into the classifier (cyclone), imparting swirl-flow to the mixture and subjecting the coal particles to centrifugal forces. Large particles are affected by larger centrifugal forces than particles of smaller size, putting the path of large particles on a larger diameter than the path of smaller particles. Particles slowed by friction can no longer stay in the particle stream and are separated from the stream, sliding down the cone wall.

Baghouses are part of the inherent design for the plant's coal milling and drying system as well. Those coal particles, which have been milled to the correct degree of fineness for use in the gasifiers, pass through the classifiers and remain in the gas flow. These coal particles are then separated from the combustion gas in the baghouse, from which the coal particles are conveyed to storage for use in the gasifiers. The combustion gas passes through the baghouse and exhausts to the atmosphere.

Venturi scrubbers mix flue gas with fine droplets of a scrubbing liquid to remove particulate. The particulate-laden liquid is then separated from the gas. To introduce the droplets into the flue gas, the gas stream is forced through a narrow venturi throat at a relatively high pressure. The pressure drop of the flue gas passing through the venturi throat is used to atomize the scrubber liquid, which is fed into the throat at relatively low pressure. Particulate removal occurs by inertial impaction between the particles and the water droplets caused by their relative velocity differences. One advantage of venturi scrubbing is its ability to handle particulate that is too "sticky" or otherwise not suitable for filtration, which is not the case for coal dust. In addition, venturi scrubbing requires a significant gas stream pressure drop, with accompanying energy consumption. The generation of wastewater, which must be properly treated before discharge, also presents an environmental impact. The typical particulate loading in the exhaust to a venturi scrubber ranges from 0.1 to 50 gr/scf while the exit grain loading from the coal dryer baghouse is expected to be only 0.005 gr/scf. Although there is considerable uncertainty about whether a venturi scrubber would provide any additional PM emissions reduction when used to control the exhaust from a baghouse that already achieves a very low exit grain loading, Christian County Generation chose to evaluate a wet scrubber as an add-on device to further reduce particulate emissions from the dryers following the product recovery in the baghouses.

Christian County Generation evaluated the cost-effectiveness of a wet scrubber downstream of the baghouse, assuming that it would further reduce PM emissions from the very low levels achieved by the baghouse. The calculations relied on USEPA annual control cost estimates for wet scrubbers based on the flow rate of the exhaust gas and the design flow rate of the coal dryers.[69] Projected costs were approximately \$28,000, \$46,000 for and \$90,000, respectively per ton of PM, PM_{10}, and $PM_{2.5}$ removed. The Illinois EPA does not consider this cost-

[69] USEPA, *Air Pollution Control Technology Fact Sheet – Venturi Scrubber*, EPA 452/F-03-017.

effective, and this control alternative was eliminated from further consideration in the BACT analysis.

Good combustion and operating practices is the only available control option for reducing PM emissions from natural gas combustion in the coal dryer burners. Good combustion minimizes the formation of soot and condensable PM.

The selected BACT control options to reduce PM emissions from the coal dryers are baghouses and good combustion and operating practices. The proposed PM, PM_{10}, and $PM_{2.5}$ BACT limits are 4.15, 2.54, and 1.32 lb/hr, respectively, all on a 3-hr average. These limits include the contribution to emissions from both coal handling and fuel combustion. An additional exit grain loading-based filterable PM BACT limit of 0.005 gr/dscf is also established for the coal dryer consistent with the approach for establishing BACT limits for the other filters and baghouses at the proposed plant.

NOx, CO, VOM and SO_2

Based on the use of low-NO_X burners, good combustion practices, and low sulfur fuel, the proposed BACT limits for the coal dryers for pollutants formed as byproducts of gas combustion are 0.031 lb/mmBtu for NO_X, 0.082 lb/mmBtu for CO, and 0.0054 lb/mmBtu for VOM, all on a 3-hr average, and 0.2 gr sulfur/100 scf fuel for SO_2. In particular, for the coal dryers, the design of the gas-fired burners and implementation of good combustion practices will be very effective in minimizing emissions of NOx, CO and VOM. This is because modern burner technology, as generally developed for firing of natural gas in boilers, may be used without any constraints being imposed on the operation or functioning of the burners as related to their emissions performance as a consequence of their use in equipment that would dry coal rather than in boilers.

Oxidation catalysts for CO control were eliminated in the BACT analysis on the basis of the associated adverse energy and environmental impacts that would accompany heating the flue gas to the temperature needed for oxidation catalyst technology to be effective. Oxidation catalysts controlling CO operate in a temperature range from about 650 to 1,150 °F. While the temperature of the hot flue gas from the burners is in this range, the gas quickly starts to cool as it comes into contact with the coal that is being dried. This is because the dryers minimize the distance between the dryer burners and the coal for optimum energy efficiency. There is not room to install an oxidation catalyst bed before the hot gas comes into contact with the coal. Accordingly, an oxidation catalyst system would have to be installed downstream of the baghouse, since the high concentrations of coal dust in the flue gas would otherwise quickly plug the catalyst bed. Downstream of the baghouse, the temperature of the flue gas from the coal dryers is less than 220 °F, well below the temperature needed for catalytic oxidation. In order to increase the gas temperature to approximately 650 °F, a gas-fired heater consuming supplemental fuel would be needed. The potential reductions in CO and VOM emissions achievable with oxidation catalysts on each of the coal dryers are only 24 and 0.9 tons/year, respectively. Based on the anticipated size of the gas heater that would be necessary to preheat the flue gas to reaction temperatures, these relatively small CO/VOM emissions reductions would be more than offset by the collateral NO_X, CO, and HAP emissions from the additional use of gas in the preheater. Therefore, oxidation catalyst technology was eliminated from further consideration in the BACT analysis on the basis of adverse energy and environmental impacts. This determination is consistent with the two entries for natural gas-fired coal dryers in the Clearinghouse and the recent CO/VOM

BACT determinations for the coal dryers at the Ohio River Clean Fuels and Summit Texas Clean Energy coal gasification facilities.[70, 71]

SCR and SNCR for NO_X control were also eliminated in the BACT analysis on the basis of adverse energy and environmental impacts resulting from the low temperature of the flue gas from the coal dryers, which is well below the necessary temperature for either SCR or SNCR. [72, 73] To raise the temperature of the coal dryer exhaust to the range needed for existing SCR technology, additional fuel heat input would be needed in a preheater. The additional fuel consumption would be accompanied by increases in emissions from the coal dryers. This determination is consistent with the Clearinghouse determinations and BACT determinations, as already discussed, for the Ohio River Clean Fuels and Texas Clean Energy project coal dryer NO_X BACT analyses. Since the gas temperature range for SNCR, between 1,600 and 2,000 °F, is even higher than for SCR, SNCR is also not an appropriate approach to reducing NO_X emissions from the coal dryers and is eliminated from further consideration as BACT. With the other add-on control options eliminated, the appropriate control option for NO_X emissions from the coal dryers is low-NO_X burners. Selection of low-NO_X burners for NO_X control is consistent with the BACT determinations in the Clearinghouse and for recent gasification projects including gas fired coal dryers.

Carbon Dioxide (CO_2)

For CO_2 emissions from fuel combustion in the coal dryers, Christian County Generation evaluated CCS, fuel selection, and efficient dryer design and operation. Since the natural gas usage and efficiency of the coal dryer burners is expected to fluctuate over a relatively wide range based on the coal throughput rate and moisture content, the fuel usage and efficiency of the coal dryers can only be controlled to the point that it does not jeopardize the ability of the coal milling and drying system to produce on-specification coal feed for the gasifiers. Regardless, for a given coal throughput rate and moisture content, Christian County Generation must use good air pollution control practices to minimize emissions, including emissions of both traditional pollutants and CO_2. Based on good air pollution control practices, the proposed CO_2e GHG BACT emission limit for the coal dryers is 78,523 tons/year, 12-month rolling basis, for the two dryers combined.

Greenhouse Gases (Methane and Nitrous Oxide (N_2O))

---

[70] Ohio EPA, Draft Air Pollution Permit-to-Install (Permit No. 02-22896) for Ohio River Clean Fuels, LLC, August 4, 2008.
(available at http://www.epa.ohio.gov/pic/ohiorivercleanfuels.aspx#submitted)

[71] Texas Commission on Environmental Quality, Special Conditions Permit Numbers 92350 and PSDTX1218, December 28, 2010.
(available at https://webmail.tceq.state.tx.us/gw/webpub)

[72] When operated with flue gas with temperatures in the range of 575 °F to 750 °F, conventional SCR systems can provide nominal NO_X removal efficiencies of between 50 and 95 percent.
Low-temperature SCR systems have been developed with claims of significant NO_X reductions in temperature ranges down to 325 °F. However, no SCR vendors have proposed or demonstrated effective NO_X reductions down to the temperature of the coal dryer exhaust gas, approximately 220 °F.

[73] It is also questionable whether either SCR or SNCR would provide any further reductions in the NOx emissions of the coal dryers. This is because of the level of NOx emissions that is to be achieved with low-NOx combustion technology and good combustion practices, i.e., 0.031 lb/mmBtu. SCR and SNCR are commonly used on flue gas streams in which the level of NOx is an order or magnitude greater than would be present in the proposed coal dryers.

Contributions to methane emissions from the coal dryers include: 1) incomplete combustion of methane in the natural gas and SNG fuels used to fire the dryer burners, 2) methane formed as a byproduct of incomplete combustion of non-methane hydrocarbons, and 3) evolution of methane from the coal during the milling, drying, and transfer operations. Although methane may continue to evolve from the coal throughout the post-mining operations (transportation, storage, milling, drying), for the purposes of conservatively calculating total plant-wide GHG emissions, it is assumed that the entire quantity of methane evolving from the coal stream is emitted during storage. Fugitive methane evolving from the coal during storage would cause higher GHG emissions on a CO_2e basis than methane evolving from the coal during drying because some of the methane may be combusted by the dryer as the flue gas is recirculated to the dryer burners to supplement and preheat the combustion air supply.

The only available control option for minimizing methane emissions from the coal dryer is good combustion and operating practices for complete fuel combustion. Although oxidation catalysts were identified as an available BACT control option for CO and VOM, manufacturers do not offer catalysts for reducing methane emissions from gas-fired coal dryers. Although good combustion and operating practices will be implemented to minimize methane emissions, a separate methane GHG BACT limit was not established. The methane emissions from the coal dryers are already included in the CO_2e GHG BACT limit.

The fuel for the coal dryers will not contain N_2O. N_2O emissions will be generated by fuel combustion in the dryer burners. Based on the N_2O to NO_X emissions tradeoff associated with LNB discussed previously, operation of the coal dryers with LNB will be required using good combustion practices in a manner that minimizes NO_X formation and not that specifically targets N_2O emissions reductions. Good design and operating practices to limit fuel consumption will, however, act to reduce N_2O emissions regardless of the burner mechanism employed. The proposed CO_2e GHG BACT emission limit includes the N_2O emissions from the coal dryers.

3. Gasifier Coal Bunker Vents (CO, VOM, and CO_2)

In addition to PM emissions from handling feed material, the gasifier coal bunker vents have gaseous emissions from depressurization of the lock hoppers that feed coal to the gasifiers. The CO_2 carrier gas vented intermittently through the gasifier coal bunker vents due to lock hopper depressurization will contain small amounts of CO (~1,400 ppm) and VOM (~16 ppm).

CO and VOM

In order to identify available control options for reducing CO and VOM emissions from this uncommon source, Christian County Generation reviewed permit applications and permits for gasification projects in North America known to be using Siemens gasifiers: Capital Power in Alberta, Canada, and Summit Power in Penwell, Texas. No available control options were identified based on this research and additional Clearinghouse searches using relevant keywords. Therefore, Christian County Generation identified thermal oxidation, catalytic oxidation, and good operating practices as available CO/VOM control options for the coal bunker vents based on control applications for similar low concentration emissions streams in other industries.

Good operating practices for the purposes of reducing CO/VOM emissions from the gasifier coal bunker vents refers to operating the lock hoppers in accordance with manufacturer's specifications, such that the frequency and duration of depressurization events are minimized to the maximum extent practicable as specified in standard operating procedures (SOPs).

Given the intermittent nature of the CO/VOM emissions episodes from the coal bunker vents, thermal and catalytic oxidation are not technically feasible for reducing CO/VOM emissions from the gasifier coal bunker vents. To efficiently reduce CO and VOM emissions from the coal bunker vents during lock hopper depressurization, the air to fuel ratio and combustion chamber dimensions of the oxidizer would have to be designed specifically for the CO and VOM loading and exhaust flow rate during these brief and intermittent depressurization events. When the lock hopper is not depressurizing, the vent exhaust flow rate drops and the CO and VOM concentrations fall to zero. With this type of variability in flow rate and CO and VOM concentration, if the vents were routed to an oxidizer, the oxidizer burner may be extinguished or the combustion chamber temperature would be greatly reduced. When the CO/VOM concentration subsequently increased during the next depressurization event, the combustion chamber temperature would likely be below the range required for efficient oxidation, assuming the oxidizer burner could even stay lit during the normal flows to the oxidizer.

Based on the use of good operating practices, the proposed BACT limits for the gasifier coal bunker vents are 21.8 and 0.34 lb/hr, 3-hour average, for CO and VOM, respectively.

Carbon Dioxide (CO_2)

Christian County Generation identified carbon capture sequestration (CCS), use of a carrier gas other than CO_2, and good operating practices as possible control options for CO_2 emissions from the vents of the coal bunkers for the gasifiers. The reasons that generally prevent CCS from being required for other units at the plant, as already discussed, also apply for these vents. In addition, CCS is not technically feasible because capture of CO_2 emissions is precluded by the nature of these vent streams, which are not suitable for application of capture technology for CO_2. These vent streams have a low gas flow rate and the CO_2 content is highly variable, with CO_2 only present in the streams intermittently, i.e., when a lock hopper is depressurized. Carrier gases other than GHG, such as nitrogen or other inert gases, cannot be used for the feed to the gasifiers because they would increase the nitrogen or inert gas concentration of the SNG above the pipeline specifications for these compounds. With a carrier gas other than CO_2 not available and no add-on control options, good operating practices are the only available BACT control option. The proposed CO_2 BACT limit is 8,217 tpy, 12-month rolling basis, for the two vents combined. The coal bunker vents are not a source of any other GHG besides CO_2, so the BACT limit is expressed in terms of CO_2, rather than CO_2e.

4. Coal Handling (Methane)

Handling of coal, including transport, storage, and processing of coal, emits methane. This is due to the methane that is naturally present in the coal, which gradually diffuses out of the coal during mining and in post-mining operations. Christian County Generation conducted a literature review to identify emission calculation methodologies and available control options for this methane. The combustion and concentrator technologies identified by USEPA for coalbed methane control are not available for reducing methane emissions from coal handling operations at the plant because of the low concentrations of methane that would be present. While USEPA has identified various methane recovery and beneficial use options for “gassy” underground bituminous coal mines, including thermal oxidation of mine ventilation air, the identified technologies are not transferable to methane emissions from coal handling at the proposed plant. Ventilation air streams from underground mines have much higher concentrations of methane than will to be present in various exhaust streams at the plant. The emission units at the proposed plant that are expected to be the largest sources of methane emissions from coal “degassing” involve storage of coal. Although the active storage dome will be equipped with a capture system and baghouse for PM emissions, which will provide capture for some of the methane emissions from the coal inside the storage dome, the concentration of methane in this stream will be so low that the emissions are not amenable to control. None of the mine ventilation stream methane control options (i.e., oxidizers alone or concentrators followed by oxidizers) would be expected to provide any additional emissions control. The open inactive storage pile, which will cover over five acres, acre would have to enclosed equipped with a ventilation system before any of the available methane control options could be implemented. Considering the relatively small amount of methane expected to be emitted from the coal in this pile and the very large air flow that would be required to capture these emissions, thermal oxidation or a concentrator system followed by thermal oxidation are also not expected to provide any additional emissions control. Therefore, these add-on control options were eliminated from further consideration in the BACT analysis.

Illinois Basin coal, the selected feedstock for the plant, has the lowest post-mining methane content of any eastern bituminous coal except coal from the Central Appalachian Basin in Eastern Kentucky.[74] At the maximum annual coal usage for the plant, use of Eastern Kentucky bituminous coal in place of Illinois Basin coal would provide a reduction in methane emissions of only 35.4 tpy (742 tpy CO_2e). The additional CO_2 emissions from transporting coal several hundred miles from Eastern Kentucky to the plant would more than counterbalance this small projected reduction in methane emissions. In addition, Christian County Generation has demonstrated that it is not cost effective to use Eastern bituminous coal for the purposes of reducing SO_2 emissions from the plant by 500 tpy, so it would be even less cost effective to reduce methane emissions by only 35.4 tpy. Therefore, use of Eastern Kentucky coal was eliminated as a BACT control option on the basis of adverse economic and environmental impacts.

Based on the maximum annual coal usage of the plant, 1,858,084 tons/year, the proposed BACT limit for methane from coal handling is 821 ton/year, 12-month running basis.

[74] Refer to Table A-114 in USEPA’s 2010 U.S. Greenhouse Gas Inventory Report (reproduced as Table 8-1 in Volume 1 of the Application) for coal methane emissions estimates, as “post-mining underground” refers to coal in post-mining operations from underground coal mines).

Part 5: BACT Discussion for the Cooling Tower

A cooling system will be associated with the gasification block to provide cooling water for certain processes for which cooling is needed.[75] Two types of cooling are generally available to industrial sources: 1) Wet cooling, in which cooling is achieved by evaporation of water in a cooling tower, which can have PM and, in some cases, VOM emissions; and 2) Dry cooling, which does not have any direct emissions and need not be addressed as a source of emissions. Since dry cooling can be considered a lower emitting process alternative to wet cooling, it is common to evaluate dry cooling as part of the BACT analysis for any portions of a proposed plant that are intended to use wet cooling. While portions of the gasification block will be served by dry cooling, portions of the gasification block will be served by a wet cooling system. Christian County Generation has evaluated the use of dry cooling as a lower emitting process alternative to this wet cooling.

Selection of Type of Cooling System

Christian County Generation has proposed a wet cooling tower to serve certain process units in the gasification block. Dry cooling in place of the proposed wet cooling system was evaluated as an inherently low emitting process to reduce PM emissions. High-efficiency drift eliminators were also considered for controlling PM emissions from the wet cooling tower. The wet cooling tower at the plant will also emit VOM emissions. This is because the ZLD distillate used as makeup water for the cooling tower may contain trace levels of VOM that may be emitted as the cooling water evaporates in the cooling tower. A reverse osmosis polisher system and good operating practices were considered for controlling VOM 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. 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. Christian County Generation has proposed dry cooling for certain portions of the gasification block, but the entire gasification block cannot be dry cooled because it is not technically possible to use dry cooling for certain cooling applications. There are certain critical heat loads that will require wet cooling because they require process temperatures that cannot be achieved with air cooling. Other loads are internal to other equipment and thus require liquid cooling of some type. While dry cooling could be further used on some components in the gasification block, such as certain compressors, use of dry cooling for those equipment is not feasible or practicable given that wet cooling is already required to satisfy the process temperature needs in several critical areas and the use of dry cooling on those few pieces of equipment would result in higher temperatures and require a significantly larger

[75] As with any power plant that uses steam to generate electricity, a cooling system will be associated with the power block at the proposed plant. This system would condense the steam leaving the steam turbine for reuse as feedwater in the HRSG and heat exchangers that generate steam for the power cycle. Christian County Generation is designing this system to use "dry cooling technology." As a consequence, the cooling system for the power block would not be a source of emissions. Since this cooling system would not be a source of emissions, the use of dry cooling for this system, which is likely a consequence of the projected water balance for the plant, does not need to address as part of the BACT determination for the proposed plant.

compressor. This renders dry cooling inappropriate for this equipment, especially considering that available water resources make the cooling system amenable to wet cooling where needed.

Particulate Matter

Because dry cooling was rejected as an alternate to the proposed wet cooling system, the use of high-efficiency drift eliminators is proposed as BACT control technology for the cooling tower. 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. Based on a high-efficiency drift eliminator, with a drift rate of no more than 0.0005 percent, the proposed PM, PM_{10}, and $PM_{2.5}$ BACT limits are 0.66, 0.20 and 0.0013 lb/hr, 24-hr average basis, respectively.

VOM

The ZLD distillate stream used to supplement the fresh makeup water supply to the cooling tower contains VOM that may be emitted in the tower. A reverse osmosis system was identified as an available control option for removing a portion of this VOM from the ZLD distillate stream before it is routed to the tower. Before undergoing reverse osmosis, the ZLD distillate would be cooled, and the VOM in the cooled distillate would then be ionized using a caustic solution. The reverse osmosis membrane would then remove the ions present in the VOM from the distillate, and the treated distillate would then be routed to the cooling water makeup system. The reverse osmosis system would also produce a reject water stream that would have to be recycled to the grey water tank and reprocessed in the ZLD wastewater treatment system.

A reverse osmosis system for removal of VOM present in the ZLD distillate was eliminated from consideration in the BACT analysis on the basis of cost. The initial installed capital cost of a reverse osmosis system is projected to be $1,500,000 and the annual costs for membrane replacements are expected to be approximately $100,000 per year. Based on a projected VOM emissions reduction for the system of 3.4 tons/year, the annualized costs for the system would be more than $29,000 per ton of VOM removed. The Illinois EPA considers this to be excessive for control of VOM. A review of entries for VOM/VOC emissions from cooling towers in the Clearinghouse did not identify any cooling towers that use an reverse osmosis system to reduce the VOM/VOC content of cooling water streams. With a reverse osmosis system eliminated on the basis of its cost impact, the only remaining BACT option is good operating practice for the preconcentrators to maintain the VOM concentration in the ZLD distillate within the design level. The proposed VOM BACT limit is 0.82 lb/hr, 3-hr average.

Part 6: Discussion of BACT for the Auxiliary Boiler and Methanation Unit Startup Heater

1. Auxiliary Boiler

The natural gas-fired auxiliary boiler would be used to periodically produce steam for the plant, including the startup of processes in the gasification block that use steam.

NOx, CO, PM/PM_{10}/$PM_{2.5}$, SO_2 and VOM

Use of natural gas, good combustion practices and ultra low-NO_X burner technology with flue gas recirculation are proposed as BACT. Given the nature of the operation of the auxiliary boiler, including infrequent and intermittent utilization, add-on control measures for CO and NO_X typically applied to combustion sources (i.e., oxidation catalyst for CO control and SCR and SNCR for NO_X control) are not cost effective.

As addressed in Sections 9.1.1 and 9.1.5 of Volume 1 of the Application, Christian County Generation determined the annualized cost-effectiveness for use of an oxidation catalyst for control of CO and VOM emissions of the auxiliary boiler. The projected costs are $6,300/ton of CO removed and $78,000/ton VOM removed. The Illinois EPA considers these costs to be excessive for these pollutants. Christian County Generation reviewed entries in the Clearinghouse for similarly sized natural gas-fired boilers, identifying four boilers that have been required to use oxidation catalyst systems for control of CO emissions. Two of the boilers are at the ConocoPhillips Refinery in Trainer, Pennsylvania. Each boiler has a maximum heat input rate of approximately 350 mmBtu/hr, which is significantly larger than the proposed auxiliary boiler at the proposed plant. These boilers are also not auxiliary boilers but "primary boilers, permitted for unlimited operation. Therefore, the cost impacts of oxidation catalyst systems on the ConocoPhillips boilers would be substantially lower than the projected costs impacts of using an oxidation catalyst system on the proposed auxiliary boiler. The two other boilers identified in the Clearinghouse are at the Turner Energy Center in Marion, Oregon and the Liberty Generating Station in Union, New Jersey. The reported CO BACT limits in the Clearinghouse are 0.038 lb/mmBtu and 0.087 lb/mmBtu, respectively. These BACT limits are less stringent than the proposed CO limit for the auxiliary boiler at the proposed plant without oxidation catalyst (0.037 lb/mmBtu). Since the pre-controlled emissions from the boilers at the Turner Energy Center and Liberty Generating Station are significantly higher than the "pre-control" CO emissions from the proposed auxiliary boiler, the cost effectiveness for these other boilers would be much lower than $6,300 calculated for proposed boiler. No other limited-use natural gas-fired boilers in the size range of the proposed auxiliary boiler were found in the Clearinghouse that have been required to use oxidation catalyst systems.

As addressed in Sections 9.1.2 of Volume 1 of the Application, Christian County Generation also determined the annualized cost-effectiveness for use of an SCR system or a SNCR system for control of the auxiliary boiler's NO_X emissions. The cost for a SCR system was determined to be $111,000/ton of NO_X removed. The cost for an SNCR system was determined to be $86,000/ton of NO_X removed. Illinois EPA considers these control costs to be excessive for NOx. Christian County Generation reviewed entries in the Clearinghouse for similarly sized natural gas-fired boilers and identified four entries for boilers using SCR for control of NO_X emissions. No boilers using SNCR were identified. The two boilers at the ConocoPhillips Trainer Refinery have also installed SCR, but, as previously discussed, these boilers are not appropriate for comparison to the proposed auxiliary boiler due to their size and mode of utilization. The other boilers using SCR are also at Turner Energy Center in Oregon and the Liberty Generating Station in New Jersey. The NOx BACT limits reported in the Clearinghouse are 0.011 and 0.036 lb/mmBtu, respectively. The 0.036 lb/MMBtu emission limit is higher than the proposed emission limit for the auxiliary boiler at the proposed plant without SCR (0.011 lb/mmBtu). The 0.011 lb/mmBtu limit is equivalent to the proposed limit for the auxiliary boiler. No other limited-use natural gas-fired boilers in the size range of the proposed auxiliary boiler were found in the Clearinghouse that have been required to use an SCR system.

The proposed BACT limits for the auxiliary boiler, on a 3-hour average basis, are 0.011 lb/mmBtu for NO_X, 0.037 lb/mmBtu for CO, 0.0075 lb/mmBtu for $PM/PM_{10}/PM_{2.5}$, 0.0054 lb/mmBtu for VOM and 0.2 gr sulfur/100 scf fuel for SO_2.

Carbon Dioxide (CO_2)

Available control options evaluated for CO_2 included CCS, fuel selection, and efficient boiler design and operation. CCS was eliminated from consideration due to the relatively low flow rate and low concentration of CO_2 in the boiler exhaust (i.e., approximately 10 percent) which makes capture infeasible and the lack of availability for a sequestration option for the plant. Various boiler efficiency measures were evaluated as candidates for improving the GHG emission performance of the auxiliary boiler including good combustion practices with a burner management system and a feedwater economizer with associated automated system to manage blowdown water flow from the boiler.

Combustion air preheating can raise the flame temperature increasing thermal NO_X formation by compromising some of the flame temperature control otherwise provided by the low-NO_X burners. Use of a feedwater economizer for heat recovery from the stack instead of air preheating, improves boiler efficiency without increasing thermal NO_X formation. The small CO_2 emissions reductions achievable with combustion air preheating are not warranted given the significant increases in NO_X emissions that are possible. Therefore, combustion air preheating was eliminated from further consideration in the CO_2 BACT analysis on the basis of adverse environmental impacts.

Efficient boiler design and operation and selection of natural gas and SNG fuel are the selected CO_2 BACT level control options for the auxiliary boiler. To ensure efficient boiler design, the draft permit requires the installation of energy efficient burners with a burner management system and a feedwater economizer. To ensure the boiler is operated efficiently, Christian County Generation must operate and maintain the boiler, including these features that are required for control of CO_2 emissions, in accordance with good air pollution control practice.

Based on these control options, the proposed CO_2 BACT limits for the auxiliary boiler is 161.5 lb CO_2e/mmBtu steam output, a 12-month rolling basis. The auxiliary boiler is designed with a high turndown capability so that it can operate over a wide range of loads (25 to 100 percent) and can meet the varying steam demands for the plant. Since the fuel-to-steam efficiency is reduced at operating loads below 80 percent, the proposed GHG BACT limit is based on the 75 percent fuel-to-steam efficiency expected during low operating loads, rather than the 82 percent efficiency the boiler is expected to achieve at loads above 80 percent.

Greenhouse Gases (methane and nitrous oxide (N_2O))

Christian County Generation will implement efficient boiler design and operation and use of good combustion practices to reduce emissions of methane and N_2O. The steam output-based CO_2e BACT limit for the auxiliary boiler includes emissions of methane and N_2O.

2. Start-up Heater for the Methanation Unit

A small natural gas-fired heater will be used for preheating the Methanation Unit primarily during startup. As such, this heater would be idle most of the time, with actual operation limited to 500 hours per year.

NO_X, CO, PM/PM_{10}/$PM_{2.5}$, SO_2 and VOM

For this start-up heater, Christian County Generation considered the same control options evaluated for the auxiliary boiler including oxidation catalyst for CO, SCR, SNCR, and LNB for NO_X, good combustion practices for CO, VOM, and PM, and fuel selection for PM and SO_2. Given the nature of the operation of this unit, including infrequent and intermittent use, oxidation catalyst, SCR, and SNCR were eliminated on the basis of excessive cost.

As addressed in Sections 9.4.1 of Volume 1 of the Application, Christian County Generation determined the annualized control cost for use of an oxidation catalyst to reduce CO emissions from this would be $152,000/ton of CO removed. The Illinois EPA does not consider this high control cost to be cost effective. A Clearinghouse search for CO BACT limits on natural gas-fired boilers and process heaters smaller than 100 mmBtu/hr revealed only one unit using oxidation catalyst for CO control. Interstate Power and Light (IPL) Emery Generating Station in Cerro Gordo, Iowa proposed an oxidation catalyst capable of achieving 80 percent CO control to reduce CO emissions for a 68 mmBtu/hr limited-use (6,000 hr/yr) auxiliary boiler. The proposed CO BACT limit for the IPL boiler is 0.0164 lb/mmBtu, and the annual control costs for this oxidation catalyst were determined to be $4,794/ton CO removed. Based on an oxidation catalyst control efficiency of 80 percent, the uncontrolled CO emission rate from the IPL boiler is 0.082 lb/mmBtu and 16.7 ton/year. Thus, the CO emission reduction offered by the oxidation catalyst at IPL is 13.4 tons/year, compared with at most only 0.7 tons/year for this start-up heater.[76] The larger size and greater annual utilization for the IPL boiler make oxidation catalyst more cost effective than it is for this start-up heater. Therefore, the CO BACT determination for the IPL boiler does not contradict the conclusion of the cost analysis for the proposed start-up heater.

As addressed in Sections 9.4.2 of Volume 1 of the Application, Christian County Generation determined the annualized control cost for use of SCR or SNCR to control NO_X emissions from this heater. The control cost for SCR is $146,757/ton of NO_X removed. The control cost for SNCR is $70,432/ton of NO_X removed. The Illinois EPA consider these costs to be excessive for control of NOx. A Clearinghouse search for NO_X BACT limits on natural gas-fired boilers

[76] The uncontrolled CO emission rate from the IPL boiler was calculated as follows: 0.0164 lb/mmBtu /(1 - 0.80) = 0.082 lb/mmBtu.
The uncontrolled annual CO emissions from the IPL boiler were calculated as follows: 0.082 lb/mmBtu x 68 mmBtu/hr x 6,000 hr/yr x 1 ton/2,000 lb = 16.7 tpy.

and process heaters smaller than 100 mmBtu/hr revealed only one unit with SCR and no unit using SNCR for NO_X control. The Valero Delaware City Refinery has a continuous-use 99.9 mmBtu/hr package boiler with SCR that is subject to a NO_X BACT limit of 0.015 lb/MMBtu. The much larger size of this boiler and the fact that it may operate continuously would make the SCR much more cost effective for this boiler than it is for this startup heater.

The proposed BACT limits for the start-up heater are 0.047 lb/mmBtu for NO_X, 0.073 lb/mmBtu for CO, 0.0075 lb/mmBtu for PM, PM_{10}, and $PM_{2.5}$, and 0.0054 lb/mmBtu for VOM, all on a 3-hr average. The proposed limit for the fuel used in the heater, to address its SO_2 emissions, is 0.2 gr sulfur/100 scf fuel.

Carbon Dioxide (CO_2)

Available control options evaluated for reducing CO_2 emissions from the methanation startup heater include CCS and efficient design and operation. CCS was eliminated for the same reasons it was eliminated for the auxiliary boiler (i.e., dilute CO_2 concentration in the exhaust and lack of a sequestration option). Heater efficiency measures evaluated explicitly included installing energy efficient burners with a burner management system, minimizing excess air, and installing a combustion air preheater. Combustion air preheating was eliminated on the basis of adverse environmental impacts attributable to collateral NO_X emissions from increased burner flame temperature.

Efficient heater design and operation and selection of natural gas/SNG fuel are the selected CO_2 BACT control technology for this heater. To ensure efficient heater design and operation, Christian County Generation must operate and maintain the heater, including features that are related to control of CO2 emissions, in accordance with good air pollution control practice. The proposed CO_2e BACT limit is 1,363 tons/year, 12-month rolling basis. The expected thermal efficiency of this heater cannot be used to form the basis of a meaningful output based CO_2 BACT emission limit since wide fluctuations in operating load are expected.

Greenhouse Gases (methane and nitrous oxide (N_2O))

Efficient heater design and operation and use of good combustion practices are proposed as BACT for emissions of methane and N_2O from this heater. The annual CO_2e BACT limit proposed for this heater would also address emissions of methane and N_2O.

Part 7: BACT Discussion for Emergency Engines

Like many facilities, the proposed plant will have engines to provide emergency electrical power when the regular supply of electricity is interrupted. It will also have engines to supply emergency power to the water pumps in the fire protection system. These engines will operate on a limited basis, when they are exercised to verify their readiness for service and on those uncommon occasions when they are actually needed to provide power during an incident. The nature of these engines is codified as the engines would be restricted to operation as emergency engines as defined by 35 IAC 211.1920, limiting their operation for no more than 500 hours annually in the absence of specific approval by the Illinois EPA. Accordingly, emissions of these engines will inherently be low and are appropriately addressed by engine design and fuel selection rather than by requirements for specific add-on emission control equipment.

Fuel Selection

The engines for the emergency generators and firewater pumps must all have their own independent fuel supply. The fuel that is proposed as an element of BACT for the engines for is ultra-low sulfur diesel fuel. Diesel fuel can be readily stored and will enable each engine to be self-sufficient with its own reserve of fuel, as is necessary for these engines to perform as emergency engines for the plant. Because of the purpose or intended function of these engines, gaseous natural gas is not considered an available fuel for these engines. This is because these engines must be available to supply power during emergencies when the natural gas supply to the plant or particular areas of the plant may be interrupted or shut off. Sufficient quantities of butane or LPG also cannot be readily stored for each engine, and such storage would pose unnecessary safety risks as compared to storage and use of diesel fuel.

CO, NOx, SO_2, and VOM

The proposed BACT limits for the engines for emergency generators are 0.29 g/hp-hr for CO, 6.4 g/kWh for non-methane hydrocarbon (NMHC) plus NO_X, 0.035 g/hp-hr for PM, 0.11 g/hp-hr for VOM and 0.041 lb/hr for SO_2. The CO and VOM BACT limits are based on the engine manufacturer’s specification sheet for the emergency generator engine model selected. The NO_X BACT limit is equivalent to the NSPS Subpart IIII NO_X emissions standard applicable to the emergency generator engines, which is itself based on the emission limits for non-road engines in 40 CFR 89.112. The total PM BACT limit is based on the manufacturer’s specifications for the filterable portion of the limit and PM emissions data from AP-42 Chapter 3.4 applicable to Large Stationary Diesel Engines for the condensable PM portion of limit. Finally, the SO_2 BACT limit is derived from the sulfur content of the ultra low sulfur diesel fuel, as must be used in the engines per 40 CFR 80.510(b). Consistent with the NSPS, compliance with the BACT limits for pollutants other than SO_2 would be accomplished by installation of engines that are certified by the manufacturer to meet the applicable emission limits. Compliance with the SO_2 limit would be addressed with recordkeeping for the fuel used in the engines.

The proposed BACT limits for the engines for firewater pump, which will be significantly smaller than the engines for the emergency generators are 0.67 g/hp-hr for CO, 2.6 g/hp-hr for NO_X, 0.090 g/hp-hr for PM, 0.086 g/hp-hr for VOM, and 0.01 lb/hr for SO_2. The CO, NO_X, and VOM BACT limits are based on manufacturer’s specifications. The PM BACT limit is based on manufacturer’s specifications for filterable PM and AP-42 Chapter 3.4 emissions data for condensable PM. Similar to the emergency generator engines, the SO_2 BACT limit is based on use of ultra low sulfur diesel fuel. Compliance with the BACT limits for pollutants other than SO_2 would be accomplished by installation of engines that are certified by the manufacturer to meet the applicable emission limits. Compliance with the SO2 limits would be determined by recordkeeping for the fuel used in the engines.

Greenhouse Gases (CO_2 and CO_2e)

Christian County Generation evaluated fuel selection and high fuel efficiency engine selection as available control options for reducing GHG emissions from the engines. As already discussed, as these engines are emergency engines, the only technically feasible fuel for these engines is diesel fuel.

Biodiesel, which is considered carbon neutral under some protocols for GHG emissions, is also not considered an available fuel for the engine. As compared to diesel oil, biodiesel has a limited “shelf-life.” Over time, the quality of biodiesel fuel would degrade in the storage tanks such that the fuel would not be of suitable quality for the engines to operate as needed during the entirety of an actual emergency incident. Alternatively, the fuel tanks for the engines would have to be drained and refilled on an appropriate schedule to maintain the quality of the stored fuel. These maintenance outages are not acceptable since they would interrupt the fuel supply to the engines, interfering with the availability of the engines for emergencies and the ability of the engines to perform their intended function.

In order to evaluate the fuel efficiency of the selected models of engines compared to other available models, Christian County Generation compared the specifications for brake specific fuel consumption (BSFC) for engines to ensure an efficient model was selected. Based on this analysis, the proposed BACT limit for the generator engines is 1,567 tons of CO_2e/year, total, 12-month rolling basis. To comply with the proposed limit, these engines would have to be designed and operated to meet a BSFC of 6,479 Btu/hp-hr. The proposed BACT limit for the smaller firewater pump engines is 328 tons CO_2e/year, total, 12-month rolling basis. To comply with this limit, these engines would have to be designed and operated to meet a BSFC of 6,647 Btu/hp-hr. [77]

Engine design and proper operation would also serve as control for emissions of methane and N_2O. The proposed BACT limits for the engines, which are in terms of CO_2e, would also address emissions of methane and N_2O.

[77] The firewater pump engines would have a higher BSFC than the emergency generator engines due to differences in the designs between the two types of engines including size (i.e., horsepower), number of cylinders, total displacement, rotations per minute of the drive shaft, and various other differences that can affect fuel consumption.

Part 8: BACT Discussion for Leaking Components

Equipment components with the potential for leaks, such as valves, pumps, compressors, and connectors, will be present in the gasification block and various other areas at the plant. Depending upon their service, these components will have the potential for emissions of CO, VOM, CO_2, and methane due to leaks. The available options for control of these emissions, in order of effectiveness, are use of "leakless" components, capture and ducting of releases and leaks from pressure relief valves (PRV) to a control device, implementation of an instrumental leak detection and repair program (LDAR), an implementation of a non-instrumental LDAR program using sound, sight and smell to identify leaks, and good work practices.[78] Other than detection of leaks by sight or smell, the above options are all technically feasible. Detection of leaks by sight is problematic for components for which only gaseous material would be leaking. Smell is problematic for CO, CO_2 and methane since they are odorless. Christian County Generation evaluated the feasible BACT options for control of emissions using procedures recommended by USEPA.

VOM

The analysis for emissions of VOM determined that a LDAR program would be cost-effective for "high-VOM components," which handle process streams with relatively high concentrations of VOM, including methanol.

The evaluation of installing leakless components on a plant-wide basis in place of conventional gas and light liquid valves and light liquid pumps for VOM-containing process streams (i.e., an average control cost analysis for installing leakless components for equipment in VOM service) showed that leakless components would not be cost effective, with a cost of over $80,000 per ton of VOM emissions avoided. There are three similar coal gasification projects that were subject to PSD review for VOM and were required to conduct a VOM BACT analysis for equipment leak component emissions: 1) Hyperion Energy Center in Union County, South Dakota, 2) Ohio River Clean Fuels (ORCF) in Wellsville, Ohio, and 3) Medicine Bow Fuel and Power in Medicine Bow Wyoming.

Hyperion and South Dakota Department of Environment and Natural Resources (DENR) considered leakless components for reducing VOM emissions from the IGCC portion of the refinery, but leakless components were eliminated from consideration on the basis that they would be less effective at reducing VOM emissions than the selected LDAR program.[79] [80]

In the issued permit for ORCF, Ohio EPA required "the use of leakless/sealless or low-emission pumps, valves and compressors" as BACT for VOM emissions from pumps, valves, and compressors in the Fischer-Tropsch (F-T) area in the plant, in which liquid fuels would be produced. However, VOM BACT requirements were

---

[78] Good work practices involve actions that minimize leaks that are present in standard operating and maintenance practices, such as leaks checks following repairs and expeditious repairs of leaks that are identified during routine inspection of equipment.

[79] Hyperion Refining, LLC, Prevention of Significant Deterioration Permit Application, December 20, 2007 (available at http://denr.sd.gov/hyperionaqpermitting.aspx#F)

[80] South Dakota DENR, Statement of Basis Prevention of Significant Deterioration Permit Hyperion Energy Center Near Elk Point Union County, South Dakota, September 11, 2008 (available at http://denr.sd.gov/hyperionaqpermitting.aspx#F)

not established for the gasification block.[81] No control cost analysis for installing leakless components in the F-T process area were provided in the ORCF application, so no comparison can be made to the control costs expected for the proposed plant. The F-T process area at ORCF has much higher uncontrolled potential VOM emissions than the proposed plant (129.4 tons/year for ORCF versus 29.1 tons/year for the proposed plant) and the number of pumps, valves, and compressors in the F-T process area are much lower than the number of these components present at the proposed plant. With higher emissions from fewer components, the cost of installing leakless components in the F-T process area at ORCF is expected to be much lower than for the VOM-containing equipment leak components at the proposed plant. Accordingly, the requirement for ORCF to install leakless components in the F-T process area does not contradict the proposed BACT determination for the proposed plant.

Finally, Wyoming Department of Environmental Quality (DEQ) only required the implementation of a LDAR program to reduce VOM emissions from the Medicine Bow industrial gasification and liquefaction (IGL) plant.[82] The permit application submitted Medicine Bow did not identify leakless components as an available control option.[83]

For "other components," which handle streams with lower concentrations of VOM, for which the total uncontrolled VOM emissions from the proposed plant are projected to be only 1.4 tons/year, an LDAR program would not be cost-effective. The cost analysis of conducting a LDAR program for these other components showed a cost of more than $100,000 per ton of VOM emissions avoided, which is not considered cost effective. While some of the other recently permitted gasification facilities are proposing to conduct a plant-wide LDAR programs as BACT for VOM emissions in accordance with requirements of relevant federal NSPS and NESHAP LDAR programs, most of these facilities are coal-to-liquids (CTL) plants (or collocated with a refinery in the case of Hyperion). As they produce liquid fuels, these facilities should be expected to have much higher uncontrolled VOM emissions from leaking equipment components than the proposed plant.

In addition, the LDAR programs selected in many cases are only applicable to equipment in VOC service, which generally means that equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. Therefore, the low-VOM components at these other gasification facilities would not be subject to the requirements of the LDAR program and are not treated any differently than they will be at the proposed plant. Although other recently permitted SNG facilities that are subject to VOM BACT requirements have not been identified, the Power Holdings, Cash Creek, and Kentucky NewGas projects are required to conduct plant-wide LDAR programs presumably to maintain HAP minor source status. Similar to the CTL plants, the selected LDAR programs for these facilities do not apply to components in VOC service. Accordingly, they exclude components with less than 10 percent VOC by weight, like the low-VOM

---

[81] Ohio EPA, Final Air Pollution Permit-to-Install (Permit Number P0106127), March 15, 2010 (available at http://www.epa.ohio.gov/pic/ohiorivercleanfuels.aspx)

[82] Wyoming DEQ, Permit Application Analysis AP-5873, June 19, 2008 (available at http://deq.state.wy.us/eqc/orders/Air%20Closed%20Cases/09-2801%20Medicine%20Bow%20Fuel%20&%20Power,%20LLC/09-2801%20Medicine%20Bow%20Fuel%20&%20Power,%20LLC.htm)

[83] Medicine Fuel & Power LLC, Prevention of Significant Deterioration Permit Application, December 31, 2007 available at http://deq.state.wy.us/eqc/orders/Air%20Closed%20Cases/09-2801%20Medicine%20Bow%20Fuel%20&%20Power,%20LLC/09-2801%20Medicine%20Bow%20Fuel%20&%20Power,%20LLC.htm)

containing process streams considered in the LDAR control cost-effectiveness analysis for the proposed plant. Therefore, the permits determinations for other coal gasification facilities are not inconsistent with the conclusions reached for the proposed plant with regard to the cost effectiveness of an LDAR program applied to low-VOM containing equipment leak components.

Based on the implementation of an LDAR program for high-VOM components in accordance with the MACT equivalent Texas Commission on Environmental Quality (TCEQ) 28VHP monitoring program with the additional requirement to conduct connector monitoring in accordance with 28CNTQ (Draft Condition 4.9.2(a)), good work practices for other low-VOM components (Draft Condition 4.9.2(b)), and routing VOM emissions from pressure relief valve leaks and releases to a flare (Draft Condition 4.9.2(c)), the proposed VOM BACT limit for all equipment leaks at the plant is 2.44 ton/year, 12-month rolling basis.[84]

CO, CO_2 and Methane

The analysis for emissions of CO, CO_2, and methane from equipment leaks found that only good work practices were cost-effective. The costs for implementation of a plant-wide LDAR program and leakless components were excessive. The cost of implementing an LDAR program was determined to be $5,400, $960 and $4,350 per ton removed, for CO, CO_2 and methane, respectively. These values are all not considered to be cost effective. For leakless components, the associated cost-effectiveness values would be higher, over $60,000, $13,000, and $65,000 per ton avoided for CO, CO_2 and methane, respectively.

The determination of excessive cost impacts for installing leakless components to reduce CO emissions is consistent with the recent determinations for the Kentucky NewGas, Cash Creek, and Summit Texas Clean gasification projects.[85] [86] [87] Illinois EPA identified only one recently permitted gasification facility that has conducted a GHG BACT analysis, Hyperion Energy Center. As discussed previously, leakless components were eliminated from consideration by Hyperion on the basis that they would not be as effective in reducing emissions as the selected LDAR program.

For similar recently permitted gasification projects, the control measures proposed as BACT for reducing CO emissions range from no controls, good work practices, and LDAR programs. A cost analysis was not submitted by any of the facilities for which a plant-wide LDAR program is required, to address whether the LDAR program would be cost-effective. In addition, none of these proposed facilities is actually operating to show that implementation of such a program is cost effective in practice. The Kansas Department of Health and Environment (KDHE) did, however, issue a final PSD permit for the Coffeyville Resources Nitrogen Fertilizer facility without any control requirements for CO BACT on the basis of an LDAR cost analysis submitted by the applicant.[88] [89] This KDHE

[84] TCEQ, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

[85] Kentucky Division for Air Quality (KDAQ), Permit Statement of Basis (Revised-Proposed) Title V/Title I-PSD, Construction/Operating Permit V-09-001 Kentucky Syngas, LLC, July 12, 2010.

[86] KDAQ, Permit Statement of Basis (Final) Title V / Title IV / Title I-PSD, CAIR Permit V-09-006 Cash Creek Generation Station, May 3, 2010.

[87] Summit Texas Clean Energy, LLC, Application for TCEQ Air Quality Permit, April 2010.

[88] KDHE, Air Emission Source Construction Permit (Source ID No. 1250079), August 6, 2007.

[89] Coffeyville Resources Nitrogen Fertilizers, PSD Permit Application, October 25, 2005.

determination supports the conclusion of the cost-effectiveness analysis for the proposed plant.

In the final permit for Hyperion, the South Dakota DENR requires the facility to implement a plant-wide LDAR program for components in greenhouse gas service which is defined as any component that contacts a fluid with greater than 5 percent methane. Since the gasification block at Hyperion would be located at a refinery that produces methane, in the form of refinery fuel gas for use as fuel at the refinery, the uncontrolled potential methane emissions from Hyperion would be much higher than the potential emission from the proposed plant. High methane concentration streams are only present at the proposed plant downstream of the Methanation Unit and in natural gas/SNG piping for the relatively small number of combustion sources at the plant. At the Hyperion refinery, methane will be present in all the petroleum-derived fuel gas streams for process heaters at the refinery and in other gaseous process streams at the refinery. In addition, pursuant to the NSPS and NESHAP, Hyperion must implement an LDAR program for VOM and organic HAPs for large portions of the refinery. The reductions in methane emissions that will accompany this LDAR program required for refinery operations will not involve any added costs. Therefore, the GHG BACT determination for Hyperion does not contradict the conclusion that the cost impacts for implementing an LDAR program for GHG emissions at the proposed plant would be excessive.

With the top ranked control options eliminated on the basis of cost, the only remaining control option is good work practices. The proposed BACT limits for CO and GHG for equipment leaks, with good work practices, are 30.5 and 1,255 tons/year, respectively, plant-wide, 12-month rolling basis.

Part 9: BACT Discussion for Roadways and Open Areas (Dust)

Christian County Generation has proposed a variety of measures, including paving (roadways), dust suppression, 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). Roadways and open areas 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 from open areas does not exceed 15 percent with compliance demonstrated based on the monthly visual observations required by Draft Condition 4.11.5(b). (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; 2) treatment of roads for effective control of emissions, to meet minimum nominal levels of control of emissions; and 3) 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.

For truck traffic on paved roadways, the BACT level control option for reducing fugitive PM emissions is water washing, sweeping, or vacuuming as necessary to achieve 90 percent nominal control. For the mobile equipment travelling unpaved storage yard for the slag landfill, the BACT level control option for reducing fugitive PM emissions is wet dust suppression that achieves 90 percent nominal control. For the mobile equipment travelling in the paved storage yard for the temporary slag pile, the BACT level control option for reducing fugitive PM emissions is periodic water flushing and sweeping that achieves 90 percent nominal control. This approach requires very effective control of PM emissions related to paved roadways, the temporary slag pile storage yard, and slag landfill as control of fugitive emissions is addressed by a minimum performance specification for the overall effectiveness of control measures.

Part 10: BACT Discussion for Other Units and Operations

1. Methanol Storage Tank (VOM)

The methanol storage tank will hold the methanol that is a component of the Rectisol® solvent for the AGR Unit. This tank will be a large tank, with a capacity of about 1 million gallons. Methanol is a VOM. Three alternatives were considered for control of emissions from the tank, namely the three options provided for organic liquid storage tanks by the NSPS and NESHAP, i.e., an appropriately fitted external floating roof, an appropriately fitted internal floating roof, or use of an add-on control device for VOM emissions, such as a vapor recovery or vapor destruction unit, with appropriate efficiency. Based on uncontrolled VOM emissions of 3.3 tpy, the tank would potentially emit about 0.07 tpy with add-on control (about 98 percent control). With an internal floating roof, the tank's potential emissions would be 0.11 tpy (96.6 percent control).[90] Due to the cost of add-on control relative to the cost of an internal floating roof, with minimal difference in VOM emissions, Christian County Generation proposed control with an internal floating roof. The Illinois EPA concurs with this conclusion based on consideration of environmental impacts. An internal floating roof will be a pollution prevention technique that will prevent loss of methanol from the tank that would otherwise need to be controlled. The use of an internal floating roof also will not consume energy like the operation of an add-on control device. The proposed VOM BACT limits for this tank are 0.11 tons/year excluding losses from roof landings and 0.25 tons/year including landing losses,.

2. Circuit Breakers (Sulfur Hexafluoride)

Circuit breakers are critical to the safe operation of electric power systems. The circuit breakers proposed for the power block and the electrical substation at the plant will contain gaseous sulfur hexafluoride (SF_6) in an enclosed-pressure system. The SF_6 will function as a dielectric to quench the electric arc that is formed when a circuit breaker is opened. SF_6 is currently the only available dielectric material for the circuit breakers for the high voltage power lines at the plant. Emissions of SF_6, from leakage of material, can be minimized by the design of the circuit breakers and appropriate instrumentation and practices. Modern SF_6 circuit breakers are fully enclosed-pressure systems that can reduce annual loss of SF_6 to less than 0.5 percent of the total SF_6 charge to the breaker. Additionally, circuit breakers can be equipped with a density alarm. Density alarms provide a warning when an amount of SF_6 above an alarm set point has escaped from the circuit breaker and enable leaks to be investigated and repaired. Based on the selection of breakers with a design leak rate of less than 0.5 percent and the use of leak detection system, a SF_6 BACT limit of 12.2 pounds/year, 12-month rolling basis, is proposed for all SF_6 circuit breakers at the plant, combined.

3. Steam Turbine Generator Maintenance (CO_2)

During periodic maintenance of the steam turbine generator in the power block, a small volume of CO_2, stored on-site in gas cylinders or a tank, will be used to purge air and hydrogen from the casing of the generator. This maintenance activity is expected to occur periodically on an annual basis in conjunction with power block outages. CO_2 is the only inert gas specified by the

[90] With an external floating roof, emissions would be 1.30 tpy (60 percent control).

manufacturer for safe purging of the casing. Accordingly other non-GHG purge gases are not available for consideration as a control option. The only available control option for this purging, which is an essential aspect of necessary maintenance, is limiting the amount of CO_2 used for purging to the amount recommended by the manufacturer. The proposed CO_2 BACT limit for this activity is 0.51 tons per occurrence.

4. Air Separation Unit (ASU) Oil Mist Fans (PM and VOM)

The large compressors in the ASU are equipped with oil lubrication systems for some of the rotating equipment in the compressors. Based on the loading of oil mist and flow rate of the oil mist vents, the PM emissions from these units are less than 0.6 tons/year, total. Oil mist is a low volatility organic material that falls in both the PM and VOM emissions category, and as such, the potential VOM emissions from the ASU oil mist fan vents are also 0.6 tpy, total. Available PM and VOM control options identified for the oil mist fan vents include mist eliminators and high efficiency fabric filters. At the low oil mist concentration in the vents of these units (i.e., ~0.02 gr/dscf), mist eliminators or fabric filters are not expected to provide any additional PM removal and, therefore, are not considered technically feasible. PM and VOM BACT limits of 0.13 lb/hr, 24-hr average, are proposed for all oil mist fan vents combined.

5. Zero Liquid Discharge Wastewater Treatment Vents (VOM)

The preconcentrators and crystallizer in the Zero Liquid Discharge (ZLD) wastewater treatment system will remove water from grey water and cooling tower blowdown in two stages, yielding a solid waste stream that would be sent off-site for disposal. The preconcentrators would drive off a portion of the water to produce a concentrated brine stream. The crystallizer will drive off the remaining water. The water-laden exhaust streams from the preconcentrators and crystallizers may contain trace levels of VOM. Given the moisture levels in these streams, the only available control option for VOM emissions from these units is an alkaline vapor scrubber. The alkaline scrubbers for these units would use caustic as the scrubbing liquid. Proposed BACT limits for VOM from the preconcentrator and crystallizer vents are 0.30 and 0.20 lb/hr, 3-hour average, respectively.

Attachment 2 – Summary of Proposed BACT Determinations

1. <u>Gasification Block</u>:

Principal Control Measures	Pollutant	BACT Limit(s)
Acid Gas Recovery Unit CO_2 Vent		
Catalytic oxidizer	CO	36.6 lb/hr, 3-hour avg.
Catalytic oxidizer	VOM	1.03 lb/hr, 3-hour avg., or 4.01 lb/hr, 3-hour avg., for startup/shutdown
Use of only natural gas or sweet syngas as supplemental fuel	SO_2	29.2 lb/hr, 3-hour avg., or 36.5 lb/hr, 3-hour avg., for startup/shutdown
Good combustion practices and use of only natural gas or sweet syngas as supplemental fuel	$PM/PM_{10}/PM_{2.5}$	0.06 lb/hr, 3-hour avg.
Gasification block process efficiency and fuel selection and good combustion practices for the catalytic oxidizer	GHG (CO_2e)	111.4 tons/million scf SNG, 12-month rolling
Sulfur Recovery Unit		
Tailgas recycle and/or thermal oxidizer and caustic scrubber	SO_2	0.63 lb/hr, 3-hour avg., or 64.4 lb/hr, 3-hour avg., for startup/shutdown 3.05 tpy, 12-month rolling
Good combustion practices	CO	1.39 lb/hr, 3-hour avg., or 19.0 lb/hr, 3-hour avg. for startup/shutdown 6.25 tpy, 12-month rolling
Good combustion practices	VOM	0.038 lb/hr, 3-hr avg., or 20.7 lb/hr, 3-hr avg. for startup/shutdown 0.27 tpy, 12-month rolling
Low-NO_X burners	NO_X	0.35 lb/hr, 3-hr avg., or 2.48 lb/hr, 3-hr avg., for startup/shutdown 1.55 tpy, 12-month rolling
Good combustion practices	$PM/PM_{10}/PM_{2.5}$	0.053 lb/hr, 3-hr avg., or 0.38 lb/hr, 3-hr avg. for startup/shutdown 0.24 tpy, 12-month rolling
Tailgas recycle, fuel selection, managing fuel consumption, LNB, and good operating practices	GHG (CO_2e)	4,937 tpy, 12-month rolling

1. <u>Gasification Block (Continued)</u>:

Flare		
Flare minimization planning (FMP), root cause analysis (RCA), good flare design, and gas-fired pilots	SO_2	9,036 lb/hr, 3-hr avg. 551 tpy, 12-month rolling
	CO	4,633 lb/hr, 3-hr avg. 315 tpy, 12-month rolling
	VOM	19.4 lb/hr, 3-hr avg. 1.14 tpy, 12-month rolling
	NO_X	129.8 lb/hr, 3-hr avg. 8.51 tpy, 12-month rolling
Water scrubber, good flare design, and gas-fired pilots	$PM/PM_{10}/PM_{2.5}$	360.7 lb/hr, 3-hr avg. 2.95 tpy, 12-month rolling
Flare design, supplemental fuel selection Flaring Minimization Planning and Root Cause Analysis	GHG (CO_2e)	26,387 tpy, 12-month rolling

2. Power Block:

Principal Control Measures	Pollutant	BACT Limit(s)
*Combustion Turbines**		
Dry low-NO_X combustors and selective catalytic reduction systems	NO_X	2 ppm @ 15% O_2, 3-hr avg., or 435 lb/event for cold startup, 120 lb/event for warm startup, 80 lb/event for hot startup,* or 90 lb/event for shutdown
Good combustion practice	CO	4.3 ppm @ 15% O_2, 3-hr avg., or 7,800 lb/event for cold startup, 2,220 lb/event for warm startup, 1,320 lb/event for hot startup, or 780 lb/event for shutdown
	VOM	0.0013 lb/mmBtu, 3-hr avg., or 920 lb/event for cold startup, 240 lb/event for warm startup, 150 lb/event for hot startup, or 100 lb/event for shutdown
	$PM/PM_{10}/PM_{2.5}$	0.0065 lb/mmBtu, 3-hr avg.
Low sulfur fuel	SO_2	0.25 grains sulfur/100 scf fuel, 3-hr avg.
Design of turbines and generators and operation with good combustion/operating practices	CO_2	1,201 lb/gross MW-hr, 12-month rolling, or 291,685 lb/event for cold startup, 72,860 lb/event for warm startup, 37,180 lb/event for hot startup, or 30,140 lb/event for shutdown
	GHG (CO_2e)	2,307,110 tpy, 12-month rolling

*Startup of a combustion turbine begins when fuel is first fired in the turbine and ends when stable operation of the burners in low-NO_X mode and the SCR system has been reliably achieved and maintained. A hot startup occurs when startup takes place when a turbine has operated within the previous 8 hours. A cold startup occurs when the turbine last operated more than 48 hours ago. A warm startup occurs when the turbine has not operated with the previous 8 hours but has operated within the previous 48 hours.

3. Material Handling and Processing Operations:

Unit(s)	Control Measures	Pollutant	BACT Limit(s)
Material Processing, Transfer Buildings, and Handling Operations	Enclosures, baghouses or vent filters, use of dust suppressants	PM	Refer to Draft Condition 4.3.2
Storage Piles and Associated Handling Operations	Use of dust suppressant	PM	Refer to Draft Condition 4.3.2
Coal Dryers	Low-NO_X burners	NO_X	0.031 lb/mmBtu, 3-hr avg.
	Good combustion practices	CO	0.082 lb/mmBtu, 3-hr avg.
		VOM	0.0054 lb/mmBtu, 3-hr avg.
	Baghouse and good combustion practices	PM	4.15 lb/hr, 3-hr avg.
		PM_{10}	2.54 lb/hr, 3-hr avg.
		$PM_{2.5}$	1.32 lb/hr, 3-hr avg.
	Low sulfur fuel	SO_2	0.2 gr sulfur/100 dscf fuel
	Efficient dryer design and operation, fuel selection, and good combustion practices	GHG(CO_2e)	78,523 tpy, 12-month rolling, combined
Gasifier Coal Bunker Vents	Good operating practices	CO	21.8 lb/hr, 3-hr avg. combined
		VOM	0.34 lb/hr, 3-hr avg. combined
	Bin vent filters	PM	0.13 lb/hr, 3-hr avg., each
		PM_{10}	0.061 lb/hr, 3-hr avg., each
		$PM_{2.5}$	0.0092 lb/hr, 3-hr avg., each
	Good operating practices	CO_2	8,217 tpy, 12-month rolling, combined
Coal Storage and Handling	Illinois Basin coal	CH_4	821 tpy, 12-month rolling

4. Auxiliary Boiler and Startup Heater

Control Measures	Pollutant	BACT Limit(s)
Auxiliary Boiler		
Low-NO_X burners	NO_X	0.011 lb/mmBtu, 3-hr avg.
Good combustion practices	CO	0.037 lb/mmBtu, 3-hr avg.
	VOM	0.0054 lb/mmBtu, 3-hr avg.
	$PM/PM_{10}/PM_{2.5}$	0.0075 lb/mmBtu, 3-hr avg.
Low sulfur fuel selection	SO_2	0.2 gr sulfur/100 dscf fuel
Efficient boiler design, fuel selection and good combustion practices	GHG (CO_2e)	161.5 lb/mmBtu of steam output, 12-month rolling
Methanation Unit Startup Heater		
Low-NO_X burners	NO_X	0.047 lb/mmBtu, 3-hr avg.
Good combustion practices	CO	0.073 lb/mmBtu, 3-hr avg.
	VOM	0.0054 lb/mmBtu, 3-hr avg.
	$PM/PM_{10}/PM_{2.5}$	0.0075 lb/mmBtu, 3-hr avg.
Low sulfur fuel selection	SO_2	0.2 gr sulfur/100 dscf fuel
Efficient design, fuel selection and good combustion practices	GHG (CO_2e)	1,363 tpy, 12-month rolling

5. <u>Other Operations and Ancillary Operations</u>:

Unit(s)	Control Measure(s)	Pollutant	BACT Limit(s)
Cooling Tower	Drift Eliminator Design (0.0005 percent drift loss)	PM	0.66 lb/hr, 24-hr avg.
		PM_{10}	0.20 lb/hr, 24-hr avg.
		$PM_{2.5}$	0.0013 lb/hr, 24-hr avg.
	Good operating practices	VOM	0.82 lb/hr, 3-hr avg.
Emergency Generator Engines	Engine combustion design	NO_X	6.4 g/kWh for NMHC + NO_X
		CO	0.29 g/hp-hr, 3-hr avg.
		VOM	0.11 g/hp-hr, 3-hr avg.
		$PM/PM_{10}/PM_{2.5}$	0.035 g/hp-hr, 3-hr avg.
	Selection of low-sulfur fuel	SO_2	0.041 lb/hr, 3-hr avg.
	Fuel efficient engine selection	GHG (CO_2e)	1,567 tpy, 12-month rolling
Firewater Pump Engines	Engine combustion design	NO_X	2.6 g/hp-hr, 3-hr avg.
		CO	0.67 g/hp-hr, 3-hr avg.
		VOM	0.086 g/hp-hr, 3-hr avg.
		$PM/PM_{10}/PM_{2.5}$	0.090 g/hp-hr, 3-hr avg.
	Low-sulfur fuel selection	SO_2	0.01 lb/hr, 3-hr avg.
	Fuel efficient engine selection	GHG (CO_2e)	328 tpy, 12-month rolling
Methanol Storage Tank	Internal floating roof	VOM	0.11 tpy, calendar year
Diesel Storage Tanks	Submerged fill & vapor balance	VOM	0.44 tpy, calendar year
Glycol Storage Tanks	None	VOM	0.44 tpy, calendar year
Leaking Equipment Components	Good work practices	CO	30.5 tpy, 12-month rolling
	LDAR for high VOM concentration components and good work practices for other components	VOM	2.44 tpy, 12-month rolling
	Good work practices	GHG (CO_2e)	1,255 tpy, 12-month rolling
Circuit Breakers	Design and leak detection system	SF_6	12.2 lb/yr, 12-month rolling
Steam Turbine Generator Purging	Management of purge gas volume	CO_2	0.51 ton/event
ASU Oil Mist Fan Vents	Operating and maintaining the compressor lubrication systems in accordance with manufacturer's recommendations	$PM/PM_{10}/PM_{2.5}$	0.13 lb/hr, 24-hour avg. combined
		VOM	0.13 lb/hr, 24-hour avg. combined
ZLD Treatment System Preconcentrators	Alkaline scrubber	VOM	0.20 lb/hr, 3-hour avg., combined

5. Other Operations and Ancillary Operations (Continued):

ZLD Treatment System Crystallizer	Alkaline scrubber	VOM	0.20 lb/hr, 3-hour avg.
Roadways and Open Areas	Paved Roads where practicable, dust control program	$PM/PM_{10}/PM_{2.5}$	Refer to Draft Condition 4.11.2

Attachment 3 - Detailed Description of the Gasification Process

The heart of the proposed plant is the production of SNG in the gasification block. The gasification block at plant will have two gasifiers, each designed to produce 50 percent of the raw syngas required for the plant when operating at maximum load. The nominal energy input to the gasification block, based on the flow of coal feedstock into the gasifiers, would be approximately 5,000 million Btu per hour. The key elements of the gasification block are the gasifiers, syngas cleanup train (water wash, Rectisol® AGR unit, and carbon bed), methanation unit, sulfur recovery unit, and the air separation unit.

The gasifiers will use the Siemens oxygen-blown, dry-fed, entrained flow process. This process includes coal and oxygen feed systems, gasifier reaction chambers, and syngas cooling. The coal feedstock is fed to the gasifiers through a feed injector that mixes the coal, water and oxygen for effective dispersion of feedstock into the gasifier and efficient operation of the gasifiers. The coal and oxygen feeds to the injector are controlled by a series of valves to facilitate safe shutdown in case of upsets.

The gasifiers are designed to operate at high pressure and at temperatures between 2,350 and 3,250 °F. The gasifiers operate in an oxygen deficient mode as needed for the physical processes and chemical reactions that produce the syngas, rather than combust the coal. The syngas from the gasifiers has a heat content of between 250 and 300 Btu per standard cubic foot on a lower heating value basis and is composed mainly of hydrogen (H_2), carbon monoxide (CO), steam or water vapor (H_2O) and carbon dioxide (CO_2).

In addition to syngas, the gasifiers also produce a coarse vitreous slag, which comes out the bottom of the gasifiers. This slag contains most of the mineral or ash matter in the coal, which is not converted into syngas and is not transported out or entrained in the syngas leaving the gasifiers. At the high temperatures in a gasifier, this material melts and flows to the bottom of the gasifier. The molten slag is removed from the gasifier through a lock-hopper. The slag is then transported to the slag handling operations. The slag solidifies into a stable glassy frit with very small amounts of residual carbon. The slag is dewatered and transported by truck for sale as a by-product or to an onsite landfill for storage.

When the syngas leaves the gasifier, it first passes through a water pool in the quench section of the gasifier where the syngas is cooled and saturated with water and slag is solidified and falls to the bottom of the vessel. The syngas exiting the side of the vessel contains entrained fine slag. It also contains significant amounts of several undesirable compounds, including hydrogen sulfide (H_2S), carbonyl sulfide (COS) and hydrogen chloride (HCl). Because of the fine slag and other undesirable components in the raw syngas, the raw syngas must undergo cleanup prior to further processing. Removal of fine slag and other undesirable components is done in a series of gas cleaning processes.

Fine slag is removed from the raw syngas first, to further cool the raw syngas and protect the subsequent gas cleanup processes. The syngas is scrubbed with water to remove entrained particles of fine slag. During this scrubbing process, hydrogen chloride (HCl), which is formed from the chlorine contained in the coal, is also removed from the raw syngas. The fine slag is comprised of unreactive mineral compounds and carbonaceous material from the coal that is not completely gasified. The dirty scrubbing water is purged from the scrubber, flashed to lower temperature and pressure, and concentrated in the black water treatment system.

The syngas from the scrubber goes to the CO shift unit. The CO shift unit is used to adjust the composition of a portion of the scrubbed syngas to establish the optimal ratio of H_2 to CO of the combined shifted/unshifted syngas fed to the methanation unit (i.e., approximately 3:1 for stoichiometric conversion via the main methanation reaction, $CO + 3 H_2 \rightarrow CH_4 + H_2O$). To accomplish this, a portion of the syngas from the wet scrubbers is heated, combined with steam, and fed to the two catalyzed shift reactors to promote the water gas shift reaction. The shift catalyst also hydrolyzes some of the carbonyl sulfide (COS) in the raw syngas, converting it to H_2S, which is more easily absorbed in the AGR Unit.

The partially cleaned syngas from the CO shift process passes through a series of heat exchangers, the Low Temperature Gas Cooling (LTGC) system, to cool the gas to near ambient temperature. The LTGC system removes liquids or process condensate from the raw syngas, as the gas is further conditioned or prepared for the mercury and H_2S removal processes. The cooled syngas then passes through a carbon bed which removes the mercury as well as certain other trace contaminants from the syngas.

The next step in the gas cleanup train is the AGR Unit for removal of H_2S and other acid gases from the raw syngas. The proposed plant will have a Rectisol® AGR Unit, using a methanol solvent countercurrent absorption column. The syngas entering the Rectisol® unit is cooled and washed with demineralized water to reduce NH_3 and HCN content. Methanol is injected as required to prevent freezing of any water in the syngas. The syngas is then washed with cold CO_2-laden methanol to remove NH_3, HCN, water and other trace impurities. In the H_2S removal section of the absorber columns, CO_2-laden methanol removes H_2S and COS from the syngas. Syngas from the H_2S removal section flows to the CO_2 absorption section, where it undergoes a staged methanol wash. The almost sulfur-free, low-CO_2 syngas is then heated and sent to a methanation unit. The AGR Unit removes over 99.5 percent of the sulfur from the syngas leaving less than 0.1 ppmv sulfur in the sweet syngas.

The CO_2 product from Rectisol® is recovered in a series of rich methanol flashing steps operating at different pressures in the solvent regeneration section of the AGR Unit. A portion of the CO_2 stream will also be used as the carrier gas for coal injection into the gasifiers. The acid gas rich solvent is stripped to reduce CO_2 content, heated, sent to a flash column, and then to a hot regenerator. A steam heated reboiler provides heat for vaporizing the methanol, and a water cooled condenser removes methanol from the acid gases leaving the regenerator. The concentrated H_2S stream from this regeneration process goes to the sulfur recovery unit.

The plant is being designed with one flare for the gasification block. The flare will be used to burn off-specification process gases during startup and shutdown. With the exception of the flare pilots required for readiness purposes, the flare will not operate during normal operation of the gasifiers.

SULFUR RECOVERY UNIT

The H_2S captured in the AGR Unit is sent to the sulfur recovery unit (SR Unit), which recovers the sulfur as elemental sulfur, using the Claus process. The recovered sulfur is a saleable byproduct from the plant. During normal, steady state operation, the tailgas from the SR Unit is sent to a tail gas treatment unit and recycled to the inlet of the AGR Unit. During certain periods of startup and shutdown, the tailgas from the SR Unit is routed to a thermal oxidizer and caustic scrubber for additional sulfur removal. The oxidizer would convert hydrogen sulfide in the tail gas to sulfur dioxide. The caustic scrubber would then control the sulfur dioxide in the tail gas prior to discharge to the atmosphere.

The thermal oxidizer and scrubber on the SR Unit would also control low volume exhaust streams from other units in the gasification block, such as liquid sulfur storage, the sour water stripper, the methanation unit, and SNG dehydration.

AIR SEPARATION UNIT

Oxygen for the gasifiers is produced at the plant in an Air Separation Unit (ASU). The ASU uses compression and very cold refrigeration to separate ambient air into oxygen (O_2) and nitrogen (N_2). The oxygen stream is in excess of 99% purity, as required for efficient operation of the gasifiers and the plant.