COMMONWEALTH OF PENNSYLVANIA **MEMO**
Department of Environmental Protection
Southwest Regional Office

TO Air Quality Permit File PA-30-00233B

FROM Alexander Sandy
Air Quality Engineering Specialist
Air Quality Program

THROUGH Alan A. Binder, P.E. *aab*
Environmental Engineer Manager
Air Quality Program

Mark R. Gorog, P.E. *mrg*
Program Manager
Air Quality Program

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RE Review of Plan Approval Application
Hill Top Energy Center, LLC
Natural Gas-Fired Combined Cycle Power Plant
Cumberland Township, Greene County
APS 936200 Auth 1174569 PF 805163

Background

On March 13, 2017, the Department received a plan approval application from Environmental Consulting & Technology, Inc. (ECT) on behalf of Hill Top Energy Center, LLC (HTEC) to construct a 620 MW natural gas-fired combined cycle power plant near the town of Nemacolin in Cumberland Township, Greene County. The project consists of a single power block in a one-on-one (1x1), combined cycle, single shaft configuration, including a combustion turbine (CT) and heat recovery steam generator (HRSG) with a steam turbine (ST). The proposed plan approval includes the following equipment:

- One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst.
- One (1) 42 MMBtu/hr natural gas-fired auxiliary boiler.
- One (1) 6.4 MMBtu/hr natural gas-fired fuel gas heater.
- One (1) 2.95 MMBtu/hr, 422 hp diesel-fired emergency firewater pump engine.
- One (1) 18.77 MMBtu/hr, 2,682 hp diesel-fired emergency generator engine.
- Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators.
- One (1) 3,000 gallon emergency generator diesel storage tank.

- One (1) 500 gallon firewater pump diesel storage tank.
- One (1) 35,000 gallon 19% aqueous ammonia storage tank.
- Lubricating oil storage tanks.
- Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR).

This application replaces PA-30-00233A which was requested to be withdrawn on January 19, 2017. According to the applicant, the project as originally conceived is no longer viable. This application requests approval for a different make and model turbine, increasing the plant's capacity from 536 MW to 620MW, due to a market decrease in the $/MW purchase price of power. The proposed project also switched from the multi-shaft configuration to a single-shaft configuration. The application was originally received on March 13, 2017, and determined to be administratively complete on April 12, 2017. A revised application was subsequently received on August 11, 2017, to address comments from the Department's Modeling Section. The following is a brief summary of the application review timeline:

1/19/2017:	Pre-application meeting
3/13/2017:	Application received
3/17/2017:	USFS response – no AQRV analysis requested
3/23/2017:	Correct application fee of $29,700 received ($31,400 originally submitted)
4/3/2017:	NPS response – no AQRV analysis requested
4/4/2017:	Modeling administrative completeness memo to SWRO
4/12/2017:	Administrative completeness letter sent to applicant
6/26/2017:	Technical deficiency sent to applicant
6/30/2017:	Response to 6/26/2017 technical deficiency received
7/12/2017:	Comments on PSD Air Quality Analysis sent to applicant
8/11/2017:	Revised application received addressing modeling comments

In the combined-cycle process, ambient air is drawn into the compressor element of the CT through an inlet air filtration and silencing system. Inlet evaporative cooling may take place during periods of warm ambient temperatures and low relative humidity to increase the overall production capability of the CT. After the evaporative cooler section, air enters the compressor section, where it is compressed and sent to the fuel/mix combustion stage of the CT. According to the applicant, this section is commonly referred to as the gas generator section. The gas generator is the component that generates criteria and hazardous air pollutant (HAP) emissions from the fuel combustion process.

A transition duct within the CT directs the flow of hot gases from the gas generator to the power section of the turbine. Gas generator combustion products (hot gases) expand through the stages of the power turbine where the thermodynamic energy is converted to mechanical power. This power is transmitted through rotation of the shaft to the generator for the CT, which is directly coupled to the turbine. The generator takes this mechanical energy and converts it to electricity.

The hot exhaust gases produced in the CT are directed into the HRSG through an exhaust transition duct, where waste heat is captured and converted into steam energy before exhaust to the atmosphere through the stack. The HRSG will contain natural gas-fired duct burners that will be used at times to increase the temperature of the exhaust gases in the HRSG to maximize output of the steam cycle in the plant.

The steam produced in the HRSG is used in the ST to produce additional electrical power. Steam is exhausted from the ST and condensed at a vacuum in the steam surface condenser. This cycle is a closed-loop system, as

the condensate is reused as feed water to the HRSG. Circulating cooling water from the cooling tower is used to condense the steam in the condenser.

The CT and duct burners in the HRSG are the primary emission units. NOx emissions will be controlled with SCR at all steady-state operating loads, with or without duct firing, to a level of 2 ppmvd corrected to 15% oxygen. CO emissions, with or without duct firing, will be controlled with catalytic oxidation to a level of 2 ppmvd corrected to 15% oxygen at all operating loads between 50 and 100 percent. With duct burner firing, VOC and PM emissions will increase slightly.

The CT/HRSG is designed to operate up to 8,760 hours per year at 100-percent load firing pipeline quality natural gas only. The CT can maintain these emission rates down to a load-range of 30-45% power. The duct burner is also designed for exclusive firing of natural gas only and is typically operated only when the CT is above 90-percent load.

Other sources include one (1) 2,682 bhp diesel-fired emergency generator and (1) 422 bhp diesel-fired emergency fire water pump engine. The diesel generator and firewater pump will only be operated during power interruptions to provide emergency power, lighting, and fire protection when the CT is not operating and, at most, once per week for less than 30 minutes for operational testing purposes when the CT is operational. The emergency generator will not be used for peak shaving.

A natural gas-fired auxiliary boiler, rated at 42 MMBtu/hr will be used primarily to provide high-temperature steam when the CT is offline to accommodate more rapid ST startups after extended shutdowns and potentially to provide fuel gas heating. It will not operate once the CT has achieved steady-state operations, however there will be some overlapping operation during startup and shutdown.

Another small natural gas-fired combustion unit associated with the CT operation will be a fuel gas heater, rated at 6.4 MMBtu/hr higher heating value. The fuel gas heater will operate as necessary to condition the natural gas prior to combustion to prevent condensation.

The project will use conventional wet cooling towers for ST steam condensation, which will operate continuously when the CT is operated. The cooling towers will emit PM associated with wet cooling tower drift losses. Drift loss will be minimized with high-efficiency drift eliminators.

Other sources include fugitive methane and carbon dioxide (CO_2) emissions due to leaks from natural gas piping, valves, flanges, compressors, etc. and from natural gas venting during piping maintenance and startup/shutdown line purging and fugitive SF_6 emissions from the circuit breakers. Fugitive emissions will be minimized by leak detection.

The project is proposed to be located on an approximately 41-acre site set back from Thomas Road, approximately 1.6 kilometers north of the town of Nemacolin in Cumberland Township, Greene County (39°53'34.900"N, 79°55'51.150"W). The project site is situated on a man-made bluff above the Monongahela River that was previously prepared for a 520 MW, coal-fired power plant that was never constructed. The property is a portion of the abandoned LTV Mining company site. The surrounding area is characterized as rural mixed with agriculture, forested land, and residential properties. The project has been given a special use permit for a power generating facility. The First Energy Hatfield's Ferry coal-fired power plant is located approximately 2.5 miles south of the project, and the Dynegy Fayette Energy Facility combined-cycle power plant is located on the other side of the Monongahela River approximately 2.5 miles south of the proposed project. The nearest residential areas to the project are Adah, which is 0.85 miles away across the Monongahela

River to the southeast, Gates, which is 0.42 miles way across the Monongahela River to the east, and Nemacolin, which is 1 mile south. The area to the west is forested and/or agricultural.

Regulatory Analysis

Federal

New Source Performance Standards

40 CFR Part 60 Subpart A – General Provisions will apply to this facility. Per 40 CFR §60.1(a), "Except as provided in subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility." HTEC will be subject to the following NSPS:

- 40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
- 40 CFR Part 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE)
- 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
- 40 CFR Part 60 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units

Applicable requirements include notifications (date of construction, initial startup, physical or operational changes, and commencement of continuous monitoring system performance); records (startup, shutdown, malfunction, and continuous monitor data); reports (continuous monitor excess emissions and performance); performance test standards; and continuous monitoring standards.

New Source Performance Standards (NSPS) from 40 CFR Part 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units will not apply to this facility. Per 40 CFR §60.40Da(e)(1), "Affected facilities (*i.e.* heat recovery steam generators used with duct burners) associated with a stationary combustion turbine that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel are subject to this subpart except in cases when the affected facility (*i.e.* heat recovery steam generator) meets the applicability requirements of and is subject to subpart KKKK of this part." The HRSG associated with the stationary combustion turbine meet the requirements of and will be subject to subpart KKKK.

NSPS from 40 CFR Part 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units will not apply to this facility. Per 40 CFR § 60.40b(a), "The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr))." The proposed auxiliary boiler is rated less than 100 MMBtu/hr (42 MMBtu/hr) and will therefore not be subject to this subpart.

Per 40 CFR § 60.40b(i), Affected facilities (*i.e.,* heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are

not subject to this subpart. The proposed combustion turbine with associated HRSG with duct burners will be subject to subpart KKKK and therefore not subject to subpart Db.

NSPS from 40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units will apply to the auxiliary boiler at this facility. Per 40 CFR § 60.40c(a), this subpart applies to units less than 100 MMBtu/hr but greater than 10 MMBtu/hr. The proposed auxiliary boiler is rated at 42 MMBtu/hr and will therefore subject to this subpart. Although the boiler will be subject to this subpart, PM and SO_2 emission standards are not applicable because the boiler will only combust natural gas. Applicable requirements include monitoring, recordkeeping, and reporting requirements.

NSPS from 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines will not apply to the proposed combustion turbine at this facility. The proposed unit will be subject to NSPS Subpart KKKK and are therefore exempt from NSPS Subpart GG per 40 CFR §60.4305(b).

NSPS from 40 CFR Part 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 will not apply to the proposed diesel storage tanks at this facility. Per 40 CFR 60.110(a), the affected facility to which this subpart applies is each storage vessel with a capacity greater than 75 m^3 that is used to store volatile organic liquid. The proposed storage tanks that may store volatile organic liquids are less than 75 m^3.

NSPS from 40 CFR Part 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) will apply to the proposed emergency generator and fire pump diesel-fired engines. Per 40 CFR 60.4200(a)(2), the provisions of this subpart are applicable to "Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or
(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006."

Emergency Generator Engine – The emergency generator engine will commence construction (be ordered) after July 11, 2005, and be manufactured after April 1, 2006; therefore, the emergency generator engine will be subject to subpart IIII. Per §60.4205(b), owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement or less than 30 liters per cylinder must comply with the emission standards in §60.4202. Per §60.4202(a)(2), engines greater than 50 bhp must be certified to the emission standards in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants. Per 40 CFR 89.112, the applicable certification standards for units greater than 560 kW are 6.4 g/kW-hr NOx+NMHC, 3.5 g/kW-hr CO, and 0.20 g/kW-hr PM. The applicant has proposed limits equal to or more stringent than these limits.

Fire Water Pump Engine – The fire pump engine will commence construction after July 11, 2005, and will be a certified National Fire Protection Association fire pump engine manufactured after July 1, 2006; therefore, the fire pump engine will be subject to subpart IIII. Per §60.4205(c), owners and operators of fire pump engines with a displacement less than 30 liters per cylinder must comply with the emission standards in table 4 of subpart IIII. For units $300 \leq HP < 600$, the applicable emission standards are 7.8 g/bhp-hr NMHC+NOx, 2.6 g/bhp-hr CO, and 0.40 g/bhp-hr PM for model years 2008 and earlier, and 3.0 g/bhp-hr NMHC+NOx and 0.15 g/bhp-hr PM for model years 2009+ (model years 2009-2011 with a rated speed greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines). The applicant has proposed limits equal to or more stringent than the 2009+ limits of this subpart.

Per 40 CFR §60.4211(c), HTEC has proposed to comply with the requirements of subpart IIII by purchasing engines which are certified to meet the applicable emission standards. Per 40 CFR §60.4207(b), HTEC has proposed use diesel fuel with a sulfur content of no more than 15 ppm and with a minimum cetane index of 40 or maximum aromatic content of 35 volume percent (from 40 CFR 80.510(b)). Furthermore, each engine will be equipped with a non-resettable hour meter; routine maintenance checks and readiness testing is limited to 100 hours per year and usage for emergency purposes will not be restricted as required by NSPS IIII. Emergency engines may also be used for up to 50 hours per year of non-emergency use, excluding use for peak shaving or producing power for sale. These 50 hours of non-emergency use count towards the 100 hours for maintenance and readiness testing.

NSPS from 40 CFR Part 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE) will not apply to any proposed sources at this facility. HTEC has not proposed to install any SI ICE.

NSPS from 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines will apply to the proposed combustion turbine at this facility. Per 40 CFR §60.4305, this subpart applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr based upon the higher heating value (HHV) of the fuel, and which commenced construction after February 18, 2005. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners. The proposed turbine will commence construction after the above date and have a HHV heat input of approximately 3,509 MMBtu/hr. Applicable requirements from this subpart include emission limitations; testing, reporting, and recordkeeping requirements; and work practice standards. Since the proposed CT is subject to subpart KKKK, it is exempt from the requirements of subpart GG, Da, Db, and Dc.

For units greater than 850 MMBtu/hr, applicable NOx emissions, including associated HRSG and duct burners, are limited to 15 ppm @ 15% O_2 or 54 nanograms per joule (ng/J) of useful output (0.43 lb/MWh). HTEC has proposed a more stringent NOx LAER limit of 2.0 ppm @ 15% O_2.

Per 40 CFR §60.4330(a)(2), for SO_2 emissions, each combustion turbine must comply with one of the following; limit emissions to less than 110 ng/J gross output, or burn fuel which contains total potential sulfur equal or less than 26 ng/J (0.060 lb SO_2 /MMBtu) heat input. HTEC will comply with this requirement by combusting pipeline quality natural gas with content less than 0.4 grains per 100 standard cubic feet. In addition to keeping records of the current, valid purchase contract, tariff sheet, or transportation contract obtained from the natural gas supplier, this plan approval will require Hill Top to sample and analyze the sulfur content on an annual basis. This is based upon the applicant's proposed frequency. The Department may change the sampling frequency based upon the analysis and stack test results.

Per to 40 CFR §60.4333(a), Hill Top will be required to operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

To demonstrate compliance with the NOx emission limits, Hill Top will install CEMS for NOx satisfying the requirements specified in 40 CFR §60.4340(b)(1). Hill Top will be required to comply with the CEMS

requirements specified in 40 CFR §60.4345 and the excess emissions requirements specified in 40 CFR §60.4350.

NSPS from 40 CFR Part 60 Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units will apply to the proposed facility. Per 40 CFR §60.5509(a), the GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 that (1) has a base load rating greater than 250 MMBtu/h of fossil fuel; and (2) serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system. The proposed stationary combustion turbine will commence construction after January 8, 2014, have a base load rating greater than 250 MMBtu/h, and serve a generator capable of selling greater than 25 MW of electricity; therefore, this subpart will apply.

Per 40 CFR §60.5520(a), affected EGUs subject to this subpart are required to meet the applicable emission standards for CO2 specified in Table 1 or 2 to this subpart. Table 2 to Subpart TTTT establishes a CO2 emission standards of 1,000 lb/MWh gross energy output for a newly constructed combustion turbine that supplies more than its design efficiency or 50 percent, whichever is less, times its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating-month rolling average basis. The proposed CT and HRSG will have CO2 emissions below this standard and will comply with the applicable monitoring, reporting, and performance test requirements.

National Emission Standards for Hazardous Air Pollutants

40 CFR Part 63 Subpart A – General Provisions will apply to this facility. Per 40 CFR §63.1(b)(1), "The provisions of this part apply to the owner or operator of any stationary source that –

(i) Emits or has the potential to emit any hazardous air pollutant listed in or pursuant to section 112(b) of the Act; and
(ii) Is subject to any standard, limitation, prohibition, or other federally enforceable requirement established pursuant to this part."

HTEC will be subject to limited requirements of a single NESHAP:

- 40 CFR Part 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Applicable requirements include only recordkeeping for applicability determinations. Per 40 CFR §63.1(b)(3), "An owner or operator of a stationary source who is in the relevant source category and who determines that the source is not subject to a relevant standard or other requirement established under this part must keep a record as specified in §63.1(b)(3)."

National Emission Standards for Hazardous Air Pollutants (NESHAPS) Subpart Q – for Industrial Process Cooling Towers will not apply to the proposed cooling tower. Per 40 CFR 63.400(a), "The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources as defined in §63.401." The proposed cooling tower will not utilize chromium-based water treatment chemicals and will be located at an area source of HAPs (<10 tons of a single HAP and <25 tons of total HAPs); therefore, this subpart will not apply.

NESHAPS Subpart YYYY – for Stationary Combustion Turbines will not apply to the proposed turbines. Per 40 CFR §63.6085 a person is subject to this subpart if they own or operate a stationary combustion turbine located at a major source of HAP emissions. The proposed facility will be an area source of HAPs; therefore, this subpart will not apply.

NESHAPS Subpart ZZZZ – for Stationary Reciprocating Internal Combustion Engines (RICE) will apply to the proposed diesel-fired generator and fire pump engines at this facility. Per 40 CFR § 63.6585, a person is subject to this subpart if they own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand. This facility will be an area source of HAP emissions and does not include stationary RICE test cells/stands. Therefore, each engine will be subject to 40 CFR 63 Subpart ZZZZ.

Per 40 CFR § 63.6590(2)(iii), each proposed engine is classified as a "new" stationary RICE since construction will commence after June 12, 2006. Per 40 CFR § 63.6590(c)(1), "new" stationary RICE have no further requirements under 40 CFR 63 Subpart ZZZZ, and meet the requirements of this part by meeting the requirements of 40 CFR Part 60 Subpart IIII.

NESHAPS Subpart DDDDD – for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters will not apply. The proposed facility will be an area source of HAPs; therefore, this subpart will not apply.

NESHAPS Subpart UUUUU – for Coal- and Oil-Fired Electric Utility Steam Generating Units (Mercury and Air Toxics Standards (MATS) Rule) will not apply to this facility. On December 21, 2011, EPA announced standards to limit mercury, acid gases and other toxic pollution from power plants. The final rule became effective on April 16, 2012. The MATS rule reduces emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF). The proposed power plant will burn natural gas only. Therefore, the proposed power plant is not subject to the MATS rule pursuant to 40 CFR § 63.9983(b).

NESHAPS Subpart JJJJJJ – for Industrial, Commercial, and Institutional Boilers Area Sources will not apply to the auxiliary boiler, HRSG, or fuel gas heater. Per §63.11237, "*Boiler* means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler.*"

The auxiliary boiler meets the definition of a gas-fired boiler that is exempt pursuant to §63.11195 (e). The HRSG is defined as a waste heat boiler, which is excluded from the definition of boiler. The fuel gas heater meets the definition of a process heater, which is excluded from the definition of boiler. As such, Subpart JJJJJJ will not apply.

Additional Federal Requirements

40 CFR Part 64 – Compliance Assurance Monitoring (CAM) will not apply to this facility. CAM applies to pollutant-specific emissions units at major sources that are required to obtain a Part 70 or Part 71 permit (i.e. Title V permit) if the following criteria are met:

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

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

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

Per 40 CFR Section 64.2(b)(1)(i), CAM does not apply to the NOx emissions from the combustion turbine with HRSG and duct burner because the NOx emissions are subject to emission limitations and standards pursuant to Section 111 of the federal Clean Air Act (NSPS Subpart KKKK). Additionally, per 40 CFR Section 64.2(b)(1)(vi), CAM does not apply to NOx and CO since each will be monitored by CEMS.

No other sources are subject to CAM because all three criteria specified in 40 CFR Section 64.2(a)(1-3) are not met.

40 CFR Part 68 – Chemical Accident Prevention Provisions will not apply to the proposed storage of anhydrous ammonia at this facility. Per 40 CFR § 68.10, an owner or operator of a stationary source that has more than the threshold quantity of a regulated substance in a process, as determined under § 68.115, is subject to the requirements of Part 68. The applicant has proposed the storage of aqueous ammonia of 19% (<20%), therefore this subpart will not apply.

40 CFR Parts 72, 73, and 75 – Acid Rain Program (ARP)– Per 40 CFR Section 72.6(a)(3)(i), the proposed facility will be subject to the Title IV Acid Rain Program since it will include new *utility units*, as defined in 40 CFR 72.2, and the unit will serve a generator that produces electricity for sale. Accordingly, the applicant will be required to submit a complete Acid Rain permit application at least 24 months prior to commencing operation per 40 CFR 72.30(b)(2)(ii).

40 CFR Part 97: Subpart AAAAA – CSAPR NOx Annual Trading Program, Subpart BBBBB – CSAPR NOx Ozone Season Group 1 Trading Program, and Subpart CCCCC – CSAPR SO_2 Group 1 Trading Program will apply to this facility. The proposed combustion turbine will be fossil-fuel-fired (natural gas), serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, and will therefore be subject to 40 CFR Part 97 AAAAA – CCCCC.

40 CFR 98—Mandatory GHG Reporting will apply to this facility. Affected sources include the combustion turbine and duct burner. The Mandatory GHG Reporting Rule requires facilities that emit greater than 25,000 metric tons per year of CO_2e to report their GHG emissions. However, the Department has been advised by U.S. EPA that emissions reporting under the Mandatory Reporting Rule is not currently considered an "applicable requirement" under U.S. EPA regulations implementing Title V and therefore does not have to be included in permits for minor or major sources. 40 CFR Part 98 and associated subparts may be applicable but this is to be determined by U.S. EPA. Applicable greenhouse gas reporting conditions may be included in an

operating permit at a later date. The Department has elected to require the reporting of GHG emissions for all sources under 25 Pa. Code § 127.12b as GHGs are now a regulated pollutant under the Clean Air Act.

Pennsylvania

General Provisions

25 Pa. Code § 121.7 – Prohibition of air pollution will apply to this facility and will be included as a plan approval condition. HTEC will meet this requirement through the plan approval application process and through compliance with the final issued plan approval.

Standards for Air Contaminants

25 Pa. Code §§ 123.1 and 123.2 – Prohibition of certain fugitive emissions and fugitive particulate matter will apply to this facility and be included as plan approval conditions.

Particulate Matter Emissions

25 Pa. Code § 123.11 – Combustion Units and **§ 123.13 – Processes** will apply to this facility and be included as plan approval conditions. Compliance with the proposed PM emission rates will ensure compliance with the limitations of §§ 123.11 and 123.13.

Sulfur Compound Emissions

25 Pa. Code § 123.21- General and **§ 123.22 – Combustion Units** will apply to this facility but are superseded by more stringent plan approval emission limits. HTEC will meet these standards through the combustion of pipeline quality gas in the turbine, duct burner, and auxiliary boiler, and by purchasing fuel oil compliant with the more stringent Federal standards for sulfur content for the diesel-fired engines.

Odor Emissions

25 Pa. Code § 123.31 –Limitations will apply to this facility and be included as a plan approval condition. Per §123.31(b), a person may not permit the emission into the outdoor atmosphere of any malodorous air contaminants from any source, in such a manner that the malodors are detectable outside the property of the person on whose land the source is being operated. The applicant has proposed to comply with the requirements of §123.31 by combusting pipeline quality natural gas and ultra-low sulfur diesel fuel only.

Visible Emissions

25 Pa. Code §123.41 –Limitations will apply to this facility but will not be included as a plan approval condition since the sources will be subject to more stringent plan approval visible emission limitations.

To ensure continued compliance with the visible, fugitive, and malodorous emission requirements, the Department will require the permittee to conduct facility-wide inspections for the presence of any visible stack emissions, fugitive emissions, and any potentially objectionable odors at the property line at a minimum of once each operating day, during daylight hours, and while the sources are operating. If visible stack emissions, fugitive emissions, and/or potentially objectionable odors are apparent, the permittee shall take corrective

action. Records of each inspection will be required to be maintained in a log and at the minimum include the date, time, name and title of the observer, along with any corrective action taken as a result.

Nitrogen Compound Emissions

25 Pa. Code §123.51 –Monitoring Requirements will apply to the duct burners. This section applies to combustion units with a rated heat input of 250 MMBtu/hr or greater and with an annual average capacity factor of greater than 30%. Per §123.51(b), the unit will be required to have continuous emissions monitoring system (CEMS) installed to monitor emissions of NOx. Although this requirement only applies to the duct burner, the applicant will comply by installing NOx CEMS on the combustion turbine/duct burner/HRSG unit.

Construction, Modification, Reactivation, and Operation of Sources

25 Pa. Code § 127.1 – New air contamination sources shall control emissions to the maximum extent, consistent with best available technology (BAT) as determined by the Department as of the date of issuance of the plan approval for the new source. All proposed sources meet the definition of a new source as defined under 25 Pa. Code §121.1 and therefore must meet BAT. BAT is further discussed below in the LAER/BACT/BAT section of this memo.

25 Pa. Code § 127.11 – Approval by the Department is required to allow the construction of an air contamination source or the installation of an air cleaning device on an air contamination source.

25 Pa. Code § 127.12b(c) – The plan approval must incorporate the monitoring, recordkeeping and reporting provisions required by Chapter 139 (relating to sampling and testing). Based on other recent plan approvals for similar sources, this plan approval will require testing within 180 days after initial startup for NOx, CO, VOC (with and without duct burners), formaldehyde, PM (filterable and condensable), PM_{10} (filterable and condensable), $PM_{2.5}$ (filterable and condensable), sulfuric acid mist, SO_2, and ammonia slip. Subsequent testing for VOC, formaldehyde and PM (filterable and condensable) will be required no less often than every five years after initial testing. The frequency for subsequent testing is consistent with other recent plan approvals for similar sources. The testing frequency may be revised based upon the satisfactory demonstration of compliance with the emission limitations by the owner/operator. Subsequent testing will not be required for NOx, CO, and ammonia slip since they will be required to be monitored with the CEMS. Since the applicant has assumed all particulate matter emissions from the combustion turbines is $PM_{2.5}$, the Department will not require separate testing for PM, PM_{10}, and $PM_{2.5}$ for subsequent tests. Sulfuric acid mist and SO_2 emissions will be calculated based upon the measured sulfur content of the natural gas, therefore subsequent testing will not be required for those pollutants.

Standards for Sources

25 Pa. Code §129.56 for storage tanks greater than 40,000 gallons capacity containing VOCs will not apply to the proposed storage tanks at this facility since they are each less than 40,000 gallons.

25 Pa. Code §129.57 for storage tanks less than or equal to 40,000 gallons capacity containing VOCs will not apply to the proposed storage tanks at this facility. The provisions of this section apply to above ground stationary storage tanks with a capacity equal to or greater than 2,000 gallons which contain VOCs with vapor pressure greater than 1.5 psia. The one (1) 500 gallon diesel storage tank will not be subject since it is less than 2,000 gallons and does not contain VOCs with vapor pressure greater than 1.5 psia. The one (1) 3,000 gallon

diesel and 31,000 gallon ammonia storage tanks are not subject since they do not contain VOCs with vapor pressure greater than 1.5 psia.

25 Pa. Code §129.91 will apply to this facility as a major source of NOx and VOC. 25 Pa. Code §129.91 requires new major sources to submit a Reasonably Available Control Technology (RACT) proposal. Alternatively, the applicant can meet the presumptive RACT emissions limitations of 25 Pa. Code §129.93. HTEC will meet the presumptive RACT limitations through the application of LAER.

25 Pa. Code §129.96 will apply to this facility. Per 25 Pa. Code §129.96(d), "This section and §§129.97-129.100 do not apply to the owner of operator of a facility which is not a major NOx emitting facility or major VOC emitting facility on or before January 1, 2017."

25 Pa. Code §§ 129.201 through 129.203 establish additional NOx requirements for boilers, stationary combustion turbines, and stationary internal combustion engines located in Bucks, Chester, Delaware, Montgomery, or Philadelphia counties. This facility is proposed to be located in Westmoreland County, therefore these sections do not apply.

Reporting of Sources

25 Pa. Code Chapter 135 establishes requirements for recordkeeping and reporting of annual emissions and will be applicable to the proposed facility. Pursuant to this chapter, this plan approval will require the applicant to maintain records necessary for the identification and quantification of actual emissions, including but not limited to, production, fuel usage, maintenance, and submit a source report by March 1 of each year for the preceding calendar year. These requirements have been included as plan approval conditions.

Sampling and Testing

25 Pa. Code Chapter 139 establishes requirements for sampling and testing and will be applicable to the proposed sources at this facility. In addition to testing, CEMS will be required for the combustion turbine by 25 Pa. Code §123.51(b) and will be subject to the requirements of 25 Pa. Code § 139.5(f). These requirements have been included as plan approval conditions.

Interstate Pollution Transport Reduction

25 Pa. Code Chapter 145 – Interstate Pollution Transport Reduction – 25 Pa. Code §145.201 incorporates by reference the CAIR NOx Annual Trading Program and CAIR NOx Ozone Season Trading Program as a means of mitigating the interstate transport of fine particulates and NOx, and the CAIR SO_2 Trading Program as a means of mitigating the interstate transport of fine particulates and SO_2. CAIR has been replaced by 40 CFR Part 97 (CSAPR) and HTEC will be required to meet the requirements of 40 CFR Part 97 Subparts AAAAA – CCCCC.

Environmental Justice

Under the guidance of the Environmental Justice Advisory Work Group, the Department developed the Environmental Justice Enhanced Public Participation Policy[1]. The policy was created to ensure that Environmental Justice (EJ) communities have the opportunity to participate and be involved in a meaningful

[1] http://www.elibrary.dep.state.pa.us/dsweb/Get/Version-48671/012-0501-002.pdf

manner throughout the permitting process when companies propose permitted facilities in their neighborhood or when existing facilities expand their operations. Appendix A of the policy includes a list of permits which trigger the EJ Enhanced Public Participation Policy. According to Appendix A – 2, Trigger Air Permits include new major sources of hazardous air pollutants or criteria pollutants; since this facility is considered a new major source of criteria pollutants, this application is considered a "Trigger Permit."

The proposed facility is to be located in Cumberland Township, Greene County, which is not designated as an EJ area; however, it is to be located within one-half mile of German Township, Fayette County, which is considered by the Department to be an EJ Community. According to the EJ Enhanced Public Participation Policy, for all trigger permits, the area of concern includes areas extending one-half mile beyond the boundary of the proposed activity. As such, Department recommended the applicant coordinate with the Department's Environmental Advocate and participate in an enhanced public participation process in a letter dated November 16, 2015, during the review of PA-30-00233A. In order to fulfill the EJ policy, an informal public meeting was held at United Mine Workers Union Hall, 92 Pershing Blvd., Nemacolin, Pennsylvania, 15351, at 7:00 PM on April 25, 2016, for an introduction to the public for the new combined cycle power plant proposed by Hill Top Energy Center, LLC. Due to the similar nature of this application compared to the previously submitted application, the Department determined that no additional public outreach was required to satisfy the EJ Policy.

New Source Review (NSR)

Prevention of Significant Deterioration (PSD) Review

Per 40 CFR §52.21(a)(2)(i) and §52.21(a)(2)(ii), any project at a new major stationary source (as defined in paragraph (b)(1) of this section) or the major modification of any existing major stationary source in an area designated as attainment or unclassifiable under the federal Clean Air Act must comply with the applicable requirements of 40 CFR Part §52.21, *Prevention of Significant Deterioration of Air Quality (PSD).* A major stationary source is defined as either:

(a) A source in one of the 28 source categories identified in 40 CFR 52.21 that has a potential to emit 100 tons or more per year of any regulated NSR pollutant;
(b) Any other stationary source that has the potential to emit 250 tons or more per year of a regulated NSR pollutant; or
(c) Any physical change which would constitute a major stationary source by itself.

Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input are listed as one of the 28 source categories; therefore, the threshold is 100 tpy of any regulated NSR pollutant for the proposed facility. Sources on the list are also required to include fugitive emissions in determining whether the source is a major stationary source.

This proposed facility is estimated to have potential emissions in excess of 100 tpy for one or more regulated NSR pollutants and will therefore be considered a new major source with respect to the PSD program. A project at a major facility for any one regulated NSR pollutant is required to be evaluated for all NSR pollutants to determine if PSD requirements are to be applied. Emission increases from this project are accounted for in step 1 and are equal to the PTE. Step 2 takes into account contemporaneous increases or decreases; however, since this is a new facility there are no contemporaneous emissions to consider. Table 2 below summarizes the PSD applicability for the proposed project.

Table 1: PSD Applicability Summary

Pollutant	Baseline Emissions	Project Emissions	Net Emissions Change	Major Source Threshold	Significant Emission Rate	PSD (Yes/No)
PM	0	111.92	111.92	100	25	Yes
PM_{10}	0	110.25	110.25	100	15	Yes
$PM_{2.5}$	0	108.18	108.18	100	10	Yes
SO_2	0	23.42	23.42	100	40	No
NO_2	0	173.10	173.10	100	40	Yes
CO	0	160.14	160.14	100	100	Yes
CO_2e	0	2,324,350	2,324,350	100,000[a]	75,000[a]	Yes
Sulfuric Acid Mist	0	13.06	13.06	100	7	Yes

[a] On October 3, 2016, EPA proposed a major source threshold and significant emission rate for CO_2e for PSD purposes.[2]

Per 40 CFR §52.21(j)(2), "A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts." As shown in Table 1 above, a best available control technology (BACT) analysis is required for all PSD pollutants, except SO_2. In accordance with 40 CFR §52.21(b), "*Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results." A summary of the BACT analysis for this project is discussed below under the LAER/BACT/BAT section of this memo.

In addition to being subject to BACT for the above listed pollutants, the applicant is required to perform a source impact analysis (modeling analysis) as required by 40 CFR §52.21(k), which is discussed in more depth in the Air Quality Modeling Analysis section of this memo.

Non-Attainment New Source Review

On May 19, 2007, the Department adopted revised New Source Review regulations in 25 Pa. Code Chapter 127 Subchapter E. Per 25 Pa. Code §127.201(a), "A person may not cause or permit the construction or modification of an air contamination facility in a nonattainment area or having an impact on a nonattainment area unless the Department… has determined that the requirements of this subchapter have been met."

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-10-03/pdf/FR-2016-10-03.pdf

25 Pa. Code §127.201(c) specifies that "The NSR requirements of this subchapter also apply to a facility located in an attainment area for ozone and within an ozone transport region that emits or has the potential to emit at least 50 tpy of VOC or 100 tpy of NOx. A facility within either an unclassifiable/attainment area for ozone or within a marginal or incomplete data nonattainment area for ozone or within a basic nonattainment area and located within an ozone transport region will be considered a major facility and shall be subject to the requirements applicable to a major facility located in a moderate nonattainment area."

25 Pa. Code §127.201(g)(1) specifies that "Beginning January 1, 2011, or an earlier date established by the Administrator of the EPA, condensable PM shall be accounted for in applicability determinations and for $PM_{2.5}$ and PM-10 emission limitations established in a plan approval or operating permit issued under this chapter." Per 25 Pa. Code §127.202(a), "The special permit requirements in this subchapter apply to an owner or operator of a facility to which a plan approval will be issued by the Department after May 19, 2007, except for $PM_{2.5}$, which will apply after September 3, 2011."

Per 40 CFR § 81.339, Cumberland Township, Greene County is classified as unclassifiable/attainment or attainment for all National Ambient Air Quality Standards (NAAQS). The entire Commonwealth of Pennsylvania is considered a "moderate" ozone nonattainment area for NOx and VOCs because Pennsylvania is a jurisdiction in the Ozone Transport Region established by operation of law under Section 184 of the Clean Air Act. For purposes of NNSR, HTEC is considered major if the PTE exceeds 100 tons of NOx or 50 tons of VOC per year. Table 2 below summarizes the NNSR applicability for this project.

Table 2: NNSR Applicability Analysis

Pollutant	Baseline Emissions	Project Emissions	Net Emissions Change	NNSR Major Source Threshold	NNSR (Yes/No)
NOx	0	173.10	173.10	100	Yes
VOC	0	60.11	60.11	50	Yes

As shown in Table 2 above, potential emissions of NOx and VOC exceed the NNSR major source thresholds. NNSR requirements for NOx and VOC include Lowest Achievable Emission Rate (LAER) and purchasing Emission Reduction Credits (ERCs). In accordance with 25 Pa. Code §121.1, LAER is defined as:

(i) The rate of emissions based on the following, whichever is more stringent:
   (A) The most stringent emission limitation which is contained in the implementation plan of a state for the class or category of source unless the owner or operator of the proposed source demonstrates that the limitations are not achievable.
   (B) The most stringent emission limitation which is achieved in practice by the class or category of source.

(ii) The application of the term may not allow a new or proposed modified source to emit a pollutant in excess of the amount allowable under an applicable new source standard of performance.

<u>Required Emissions Offsets</u>

In accordance with 25 Pa. Code §§ 127.205(4) and 127.210, HTEC will be required to purchase ERCs to offset the NOx and VOC emission increases associated with this project at a ratio of 1.15:1. Based on the PTE, the following table represents the required ERCs to be purchased:

Table 3: Required ERC Summary

Pollutant	PTE	Ratio	ERCs
NOx	173.10	1.15	200
VOC	60.11	1.15	70

In accordance with 25 Pa. Code §§ 127.206(d)(1), "The ERCs shall be identified in a Department approved and Federally enforceable permit condition for the ERC generating source. The permit condition will provide that the ERCs are properly generated, certified by the Department and processed through the registry no later than the date approved by the Department for commencement of operation of the proposed new or modified facility."

In accordance with 25 Pa. Code §§ 127.206(d)(2), "The owner or operator of the proposed new facility may not commence operation until the required emissions reductions are certified and registered by the Department."

Alternatives Analysis

In accordance with 25 Pa. Code § 127.205(5), "For a new or modified facility which meets the requirements of and is subject to this subchapter, an analysis shall be conducted of alternative sites, sizes, production processes and environmental control techniques for the proposed facility, which demonstrates that the benefits of the proposed facility significantly outweigh the environmental and social costs imposed within this Commonwealth as a result of its location, construction or modification."

An alternatives analysis has been performed and according to the applicant, the analysis "…demonstrates the benefits from construction of a new combined-cycle unit as proposed significantly outweigh the associated environmental and social costs because (1) the location of the new plant at the already-developed power plant site will provide electrical generation capacity without impacting a new site or requiring extensive construction of infrastructure, and (2) the NO_x and VOC emissions offsets obtained by Hill Top will ensure a net reduction in NO_x and VOC emissions in the ozone transport region in Pennsylvania." The analysis is included in Section 6.0 of HTEC's application. At the Department's request, additional supporting information was provided in a letter dated June 30, 2017. Below is a summary of the analysis.

Alternative Sites

HTEC considered the following factors in its identification and screening of potential sites:

- Proximity and availability to large electric transmission lines;
- Sufficient availability of natural gas supply;
- Existing character of the site (zoning and land use criteria) and surrounding area (i.e., developed, industrial);
- Impacts to threatened or endangered species or species of special concern;
- Impacts to wetlands and streams;
- Impacts to cultural resources;
- Feasibility of completing construction at the site in time for the planned commercial operation date of June 2020; and
- Overall environmental impacts, including air quality impacts, of the proposed Project.

HTEC has proposed to locate the plant in the PJM area due to its proximity to major load centers on the eastern seaboard to lessen transmission line losses and need for additional transmission upgrades. Furthermore, Southwestern Pennsylvania was selected for its location within the PJM and the following sites were evaluated: Isabella site in Fayette County; Labelle site in Luzerne Township, Fayette County; Nemacolin site located in the Village of Nemacolin, Greene County, and Ward site located in Cumberland Township, Greene County.

Hill Top eliminated the Isabella site due to higher cost to interconnect at 500 kV (into Yukon-Hatfield line) due to greater distance and resulting increased environmental impact and higher right-of-way expense; the site is not prepared and ready to construct foundations; and the site was previously deep mined.

Hill Top eliminated the Labelle site due to proximity to residences, the electrical interconnection is not located to serve the highest demand areas, and the site was previously deep mined.

Hill Top eliminated the Nemacolin site due to the proximity to residential properties, the potential impact to the wetlands located on the site, and the site was previously deep mined.

Hill Top chose the Ward site based on the following factors in their identification and screening of potential sites:

- Proximity to Monongahela River for cooling tower water
- Proximity to Texas Eastern Transmission TETCO M-2 pipeline for natural gas supply
- Proximity to electric interconnection point within PJM (Hatfield's Ferry 500 kV substation with access to the Trans-Allegheny Interconnection Line (TrAIL))
- Positive economic impact for local skilled labor
- Site is appropriately zoned for a power plant with support from Cumberland Township
- Stable soil and seismic conditions, good hydrology, and is level, prepared, and ready for construction since the site was previously developed for a power plant
- Higher elevation for dispersion of potential air contaminants
- Distance from nearest residential properties
- No onsite wetlands, streams, encroachments, floodplains, or endangered species that could potentially be impacted

Alternative Sizes

HTEC is sized to reliably and efficiently provide a portion of the electricity needed due to the retirement of coal-fired power plants within the PJM. Considering the capacity of the electrical grid, efficiencies associated with natural gas pipeline operations and limiting environmental and social impacts, HTEC is proposing to build a 1×1 combined-cycle unit with a nominal rating of 620 MW. A second unit can be accommodated on the Project Site if needed in the future but is not part of this application.

Alternative Production Processes

HTEC considered renewable energy, including solar photovoltaic, biomass, and wind power; other fossil fuels; and other combustion processes within PJM service territory. According to the applicant, while significant federal and state monetary incentives and subsidies are available for solar photovoltaic (PV) and wind power, it was determined that the application of utility-scale solar energy or wind power (500 MW or greater) would require too much land and would be socially and environmentally unacceptable and technically impractical:

- Solar Photovoltaic—Solar energy has limited potential in Cumberland Township, Greene County, due to lack of available land and taking into consideration that the average solar energy intensity of the area is poor. Solar energy was therefore considered both technically unfeasible and uneconomic.

- Wind Power—Wind power on a utility scale was deemed impractical in Cumberland Township, Greene County, due to the lack of sufficient and available land as well as the poor wind energy profile. Wind power was therefore considered both technically unfeasible and uneconomic.

- Land Required—Utility-scale wind farms typically require approximately 50 to 60 acres per installed MW of nameplate-capacity; therefore, an equivalent wind farm would require approximately 31,500 acres of land (approximately 50 square miles). A ground-mounted solar energy facility, using as an example Snyder's Lance 12,092-panel solar energy array in Hanover, Pennsylvania (3.5-MW nameplate rating), requires approximately eight acres of land per installed MW nameplate capacity. A solar energy plant equivalent to HTEC would require approximately 4,600 acres of land, or approximately 7.1 square miles. The applicant has determined this is socially, technically, and commercially unfeasible.

- Capacity Factor—Hill Top will be capable of operating at capacity rating 8,760 hr/yr or on demand, whereas neither solar photovoltaic (at approximately 15-percent capacity factor) nor wind power (at 22-percent capacity factor) can achieve this capacity or flexibility. Both solar energy and wind power would therefore require addition of conventional fuel backup generation.

Plants using other fossil fuels (coal or oil) were removed from consideration because the cost (on a dollar-per-kilowatt basis) was much higher than that of a comparably sized natural gas plant. Further, even with the installation of control technologies on coal or oil plants, the resulting environmental impacts were still greater than a comparably sized natural gas plant.

Other natural gas power generation processes (e.g., reciprocating engines, boilers, CTs) and energy recovery cycles (e.g. simple-cycle, combined-cycle, combined heat and power) were also considered. CTs in combined-cycle operation were determined to be the most efficient as represented by heat rate in terms of Btu/kWh. According to the applicant, they have the lowest cost to construct, operate, and maintain on a dollars-per-megawatt basis. They also have a shorter construction schedule and less acreage needed for the plant footprint. Hill Top considered various CT, HRSG, and control system designs and manufacturers and has chosen a 1×1 configuration with HRSG for the overall efficiency, flexibility, and capacity required.

<u>Alternative Control Technologies</u>

A detailed discussion and analysis of alternative control technologies is included in the LAER/BACT/BAT analysis section of this memo. The Project was required to perform a BACT analysis for criteria pollutants since the proposed Project is subject to PSD. Furthermore, the Project is subject to LAER for NOx and VOC due to the potential emissions and since the area is in an ozone transport region. LAER is generally considered the most stringent level of control required under the CAA. Based on the results of the analysis, HTEC will employ air pollution control technology equivalent to or more stringent than other similar sources in the United States. The Project will also be fueled exclusively with natural gas, which will result in lower emissions of criteria pollutants, such as NOx, SO_2, PM, and CO_2, compared to alternative fossil fuels. In addition, the ERC offsets Hill Top will be required to obtain before operating to meet NNSR requirements for NOx and VOCs will ensure a net decrease in NOx and VOC emissions for the ozone transport region as a whole.

Hill Top has proposed an advanced CT, equipped with dry low-NOx combustion technology in the primary mode of operation to prevent emissions of NOx from forming, as well as efficient combustion design that will minimize the formation of CO and VOC at the same time. The exhaust from the CT/HRSG will be equipped with an SCR system and an oxidation catalyst to control emissions of NOx, CO, and VOC from the CT and the HRSG duct burners. This system also controls the small amounts of some HAPs (e.g. formaldehyde) that are created in the combustion process.

The plan approval application demonstrates that the proposed facility will meet the applicable requirements of 40 CFR Part 52.21 (related to Prevention of Significant Deterioration) and 25 Pa. Code Subchapter E (related to Nonattainment New Source Review), and will incorporate Best Available Technology pursuant to 25 Pa. Code §127.1. Based on the information provided in the application (including supplemental information requested by the Department), the Department has determined that HTEC's analysis required by 25 Pa. Code §127.205(5) is acceptable.

LAER/BACT/BAT Analysis

With respect to attainment pollutants and as previously discussed in this memo, since HTEC's potential to emit for NO_2, CO, PM, PM_{10}, and $PM_{2.5}$ exceeds 100 tpy, the facility is subject to BACT for each of these pollutants. The facility is also subject to BACT for GHGs since the facility is an "anyway" source and for H_2SO_4 since the PTE exceeds what is considered significant (>7 tpy) for this pollutant as defined in 40 CFR §52.21(b)(23). Furthermore, HTEC is also subject to LAER for NOx and VOC. The proposed sources are also subject to BAT to prevent, reduce, or control emissions of other air contaminants, such as HAPs.

The applicant has conducted the BACT review following a 5 step "top down" analysis which has been recommended by EPA for attainment pollutants as well as GHGs.

1. Identify all available control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by effectiveness
4. Evaluate the most effective controls and document results
5. Select BACT

The applicant conducted the LAER analysis for NOx and VOC using the following three steps[3]:

1. Identification of available control technologies
2. Evaluate technical feasibility of identified technologies and identification of most stringent existing permit limits
3. Propose LAER based on the feasible technology and the most stringent emissions limit that has been *achieved in practice*.

HTEC has used EPA's RACT/BACT/LAER Clearinghouse (RBLC) to search for projects of similar size and nature as the proposed project. A number of projects were identified and determined by the Department to be of close, but not identical, size and nature as the proposed project; and therefore, removed from the analysis. Also considered were other recent plan approvals for similar sources. The following is a summary of the LAER/BACT/BAT determinations and their respective emission limits made by the Department, taking into

[3] An important differentiation between BACT and LAER is that LAER does not consider cost.

consideration available control technologies, other recent plan approvals, limitations achieved in practice, and the RBLC.

NOx LAER/BACT/BAT Analysis – CT/HRSG

In combustion processes, NOx is primarily formed by two mechanisms: fuel NOx and thermal NOx. NOx formation from natural gas combustion is primarily thermal NOx. Since pipeline quality natural gas contains little or no fuel-bound nitrogen, fuel NOx is not a major contributor to NOx emissions from natural gas-fired combustion turbines. Thermal NOx is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and react to form NOx. Factors affecting the formation of thermal NOx are combustion temperature, concentration of oxygen in the inlet air, and residence time. Prompt NOx is a third possible formation mechanism where early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals in the fuel form prompt NOx. However, the contribution of prompt NOx to overall NOx formation is negligible.

Identification of Potential Control Techniques for NOx/NO_2

NOx reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that reduce peak flame temperature and/or introduce combustion products that limit initial NOx formation. Several post-combustion NOx control technologies are potentially applicable to the proposed facility. These technologies employ various strategies to chemically reduce NOx to N_2 with or without the use of a catalyst. Combustion control techniques analyzed by HTEC include water/steam injection, dry low-NOx combustors, and catalytic combustion controls. Post combustion control techniques analyzed include selective non-catalytic reduction (SNCR), nonselective catalytic reduction (NSCR), selective catalytic reduction (SCR), and SCONOx.

Water/Steam Injection – Injection of water or steam into the primary combustion zone of a CT reduces formation of thermal NOx by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to vaporize the water (latent heat of vaporization) and raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion or deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NOx reduction in comparison to water injection. Water or steam injection will not reduce the formation of fuel NOx.

Dry Low-NOx combustors – Dry low-NOx combustors are designed to premix turbine fuel and air prior to combustion in the primary zone. The use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. This allows a lower flame temperature in the combustion zone, causing a decrease in thermal NOx emissions.

Catalytic Combustion Controls (XONON) – XONON is a patented catalytic combustion system developed by Catalytica, Inc.(now owned by Kawasaki) and operates by partially burning fuel in a low-temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low-temperature partial combustion followed by flameless catalytic combustion which is capable of achieving NOx exhaust concentrations less than 3.5 ppm.

Selective Non-Catalytic Reduction (SNCR) – The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NOx in the exhaust gas stream with injected ammonia or urea to yield nitrogen and water vapor. According to the applicant, the two commercial applications of SNCR include the Electric Power Research Institute's NOxOUT™ and Exxon's Thermal DeNOx™ processes. The two processes are similar in that either ammonia (Thermal DeNOx™) or urea (NOxOUT™) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. The optimal temperature range for SNCR is approximately 1,600 to 2,000° F. Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NOx.

Nonselective Catalytic Reduction (NSCR) – The NSCR process uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor under fuel-rich (less than 3-percent oxygen) conditions. According to the applicant, NSCR technology has only been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction (SCR) – In contrast to SNCR, SCR reduces NOx emissions by reacting ammonia with exhaust gas NOx to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed. The catalyst serves to lower the activation energy of the reactions, which allows NOx conversions to take place at a lower temperature than SNCR. According to the applicant, the optimum temperatures range from as low as 350°F to as high as 1,100°F (typically 600 to 750°F), depending on the catalyst. Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics. Reaction temperature is critical for proper SCR operation. Below the optimal temperature range, the reduction reactions will not proceed, and unreacted ammonia is exhausted (ammonia slip). At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NOx emissions. NOx removal efficiencies for SCR systems typically range from 80 to 90 percent.

EMx/SCONOx – This multipollutant reduction catalytic control system is a complex technology designed to simultaneously reduce NOx, VOC, and CO through a series of oxidation/absorption catalytic reactions. EMx/SCONOx uses 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 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 separated by louvers, with one section offline at all times for regeneration.

Elimination of Technically Infeasible Control Options

SNCR is considered technically infeasible because the temperature required (between 1,600 and 2,000°F) exceeds the CT exhaust temperature. NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent oxygen) environment. The oxygen content of the proposed CT exhaust gases is in excess of 12 percent. Since EMx is not commercially available for the size of combustion turbine proposed, EMx has been determined to be technically infeasible. Similarly, XONON is not commercially available on large units as proposed in this project. Therefore, XONON has also been determined to be technically infeasible.

Selection

The determination for control of NOx is good combustion practices, dry low-NOx combustors, and SCR. The proposed emission limitation is 2.0 ppmvd corrected to 15% O_2 on a 3-hour averaging period with or without duct burner firing. Review of the RBLC database and other recent plan approvals for similar sources indicates

that the proposed NOx emission limit satisfies LAER for this type of source, except for the averaging time. Upon further review of the RBLC, including LAER determinations for Virginia Electric and Power Company Warren County Power Plant and Virginia Electric and Power Company Brunswick County Power Plant, and recent comments from EPA on CPV Fairview, LLC, the Department has determined that a more stringent, 1-hour averaging period constitutes LAER for this source for continuous compliance. Initial compliance, demonstrated using EPA reference test methods, will be on a 3-hour averaging period.

HTEC will also be required to continuously monitor and record the NOx emission rate and ammonia emission rate with CEMS to ensure proper operation. Maintenance will also be required per the manufacture's recommendation. In conjunction with the imposed NOx LAER, an ammonia (NH_3) slip limitation of 5 ppm pursuant to BAT will be imposed.

CO BACT/BAT Analysis – CT/HRSG

CO emissions are a by-product of incomplete combustion due to insufficient oxygen availability, poor air/fuel mixing, reduced combustion temperature, and/or reduced combustion gas residence time within the high temperature combustion zone.

Identification of Potential Control Techniques

HTEC has identified good combustion practices and oxidation catalyst as potential control technologies for CO. Other potential control technologies include EMx/SCONOx and XONON. For a description of EMx/SCONOx and XONON, please refer to the NOx analysis above.

Good Combustion Practices – Good combustion practices include optimization of the combustion chamber designs and operations to improve the oxidation process and minimize incomplete combustion. This includes utilizing lean combustion to produce a cooler flame temperature while still ensuring good air/fuel mixing with excess air to achieve complete combustion.

Oxidation Catalyst – Oxidation catalysts oxidize CO in the exhaust stream by utilizing a precious metal catalyst. Oxidation efficiency depends on temperature, exhaust flow rate (since sufficient residence time is required for oxidation to occur), and catalyst composition.

Elimination of Technically Infeasible Control Options

EMx/SCONOx and XONON have the potential to reduce CO emissions; however, these technologies were previously determined to be technically infeasible for NOx for the proposed unit. Similarly, for CO, EMx/SCONOx and XONON have not been demonstrated on the size of CT proposed.

Selection

HTEC has proposed to control CO through the use of good combustion practices/burner design and oxidation catalyst. Based on the provided manufacturer's information along with review of the RBLC and BAT for other recently issued plan approvals for similar sources, the Department has determined the appropriate CO emission rate is 2.0 ppmvd @ 15% O_2 on a 1-hour averaging period (for consistency with NOx averaging period).

HTEC will also be required to continuously monitor the CO emission rate with CEMS to ensure proper operation. Maintenance will be required per the manufacture's recommendation. In addition to the above

requirements, HTEC plans to inspect the catalyst on an as-needed basis and will place "coupons" in the catalyst bed to analyze the functionality and ensure the performance of the catalyst.

VOC LAER/BAT Analysis – CT/HRSG

VOC emissions are a by-product of incomplete combustion of fuels caused by reduced combustion temperature, poor air/fuel mixing, and decreased residence time within the combustion zone. VOC emissions are also dependent on the loading of the turbine. Emissions of VOC will generally increase during turbine partial load conditions when combustion temperatures are lower. The potential control technologies for VOC are the same as those for CO, described above. Similarly, to the CO determination, BAT for VOC is good combustion practices and installation and operation of an oxidation catalyst.

Based on the manufacturer's specifications, HTEC proposed two separate VOC LAER limits, one for operation with duct burners and one without duct burners. The proposed emission rates are 2.0 ppmvd @ 15% O_2 with duct burners and 1.0 ppmvd @ 15% O_2 without duct burners.

Using the above combinations of good combustion practices and oxidation catalyst, review of the RBLC and recent authorizations for similar sources, the Department has determined that the proposed emission limits constitute LAER for the proposed CT and HRSG with duct burners. The RBLC identifies several facilities which are subject to lower emissions rates, however, the facilities utilize turbines which are not comparable in size or the limits have not been demonstrated in practice, and therefore, these limits do not constitute LAER for the proposed source and cannot be imposed.

PM/PM_{10}/ $PM_{2.5}$ BACT/BAT Analysis – CT/HRSG

Identification of Potential Control Techniques

HTEC has analyzed various post-combustion control techniques for the control of particulate matter including cyclones, electrostatic precipitator (ESP), baghouse/fabric filters, and wet scrubbers. HTEC has also analyzed the use of good combustion practices and use of low sulfur fuel.

Elimination of Technically Infeasible Control Options

Due to the inherently low total PM emissions rates associated with low-ash and low-sulfur fuels in combustion turbines, add-on filtration or collection devices would exhibit very low control efficiencies, and as a result, high cost to control efficiency ratio. Also, a review of the RBLC showed no combined cycle units equipped with add-on controls.

Selection

HTEC has determined that good combustion practices with the use of low sulfur natural gas to satisfy BACT/BAT for the proposed unit. HTEC has also proposed total PM emission limits of 0.0071 lb/MMBtu without duct burner firing and 0.0072 lb/MMBtu with duct burner firing. HTEC has made note that it is difficult to make comparisons of numerical BACT emissions limits with respect to PM/PM_{10}/$PM_{2.5}$ emissions for several reasons. First, some of the queried results represent emissions limits based on only the filterable portion of total PM/PM_{10}/$PM_{2.5}$ emissions. If the condensable portion, including sulfates generated during the combustion process, is not included, a lower lb/MMBtu emissions limit will result. Secondly, the emissions limits that do contain both the filterable and condensable portion are based on widely varying natural gas sulfur

contents. Sulfur in the fuel is converted to sulfates during the combustion process, and these sulfates add to the condensable portion of the total $PM/PM_{10}/PM_{2.5}$ emissions. Facilities that have higher short-term natural gas sulfur content have higher $PM/PM_{10}/PM_{2.5}$ emissions based solely on the condensable portion. Furthermore, there are no PM limits in any NSPS applicable to turbines and the proposed fuel sulfur content limit is more stringent than any SO_2 under NSPS Part 60 Subpart KKKK for turbines. The Department has determined that the proposed emission rates are appropriate.

H_2SO_4 BACT and SO_2 BAT Analysis – CT/HRSG

Sulfuric acid mist (H_2SO_4) emissions result from the reaction of SO_3, formed from the oxidation of SO_2, with water. Uncontrolled H_2SO_4 and SO_2 emissions both depend on the sulfur content of the fuel. H_2SO_4 emissions also depend on the oxidation of SO_2 to SO_3, followed by the subsequent conversion of SO_3 to H_2SO_4 when water vapor is present. H_2SO_4 emissions are not necessarily dependent upon combustion turbine properties such as burner design.

Identification of Potential Control Techniques

Control techniques considered include use of low sulfur fuel and post-combustion add-on controls to reduce SO_2 and H_2SO_4 such as flue gas desulfurization (FGD) scrubber and dry sorbent injection.

Low Sulfur Fuel – Low sulfur fuels are considered technically feasible to be utilized in CTs with HRSG and duct burners as a technique to reduce SO_2 and H_2SO_4 (through SO_2 reduction). The lower the amount of sulfur in the fuel, the lower potential conversion of sulfur to SO_2.

Flue Gas Desulfurization (FGD) – FGD scrubbers remove sulfur compounds from exhaust streams by using an alkaline reagent to form sulfate and sulfate salts. The reaction of SO_2 with the alkaline can be performed using either a wet or dry contact system. Dry sorbent injection involves the reaction of a calcium or sodium-based sorbent with SO_2 and SO_3. The reduced availability of SO_2 and SO_3 in the exhaust stream reduces H_2SO_4.

Elimination of Technically Infeasible Control Options

No applications have been identified of FGD scrubbers or dry sorbent injection on natural gas-fired combustion turbines due to low SO_2 and H_2SO_4 emissions. Due to the low concentration of H_2SO_4 in the exhaust gas, neither the FGD scrubber nor dry sorbent injection would provide measurable emission reduction. Application of FGD to the turbine exhaust would also cause significant pressure drop in the exhaust ducting and would require the addition of a fan which would result in additional parasitic plant load and potential air/fuel mixing problems. Based on the insufficient operating history of these control technologies on similar units, these methods are considered technically infeasible. This is consistent with determinations listed in the RBLC and other recent plan approvals.

Selection

Due to the elimination of add-on control options, it has determined the appropriate control technique to be combustion of pipeline quality natural gas with low sulfur content. HTEC has proposed H_2SO_4 emission limits of 0.0086 lb/MMBtu with and without burner. More stringent limits have been identified in the RBLC, however since no add-on controls are proposed, the H_2SO_4 emissions are based primarily on the sulfur content of the natural gas available in the region and the conversion of SO_2 to SO_3 and SO_3 to H_2SO_4. Therefore, the

proposed emission limits have been determined to be appropriate. Furthermore, the Department isn't aware of any facilities that incorporate fuel sulfur removal or reduction on fuel gas supplies to achieve more stringent limits. Permit limitations which apply to a pollutant of which the emission rate varies according to the fuel sulfur content should allow for expected fluctuations thereof. The proposed H_2SO_4 emission rates account for such fluctuations.

Combustion of pipeline quality natural gas also meets the SO_2 BAT requirements. This also meets the SO_2 standards under NSPS Subpart KKKK. Short-term emissions were based on the maximum fuel sulfur content of 2.0 gr/100 scf, and annual emissions were based on the average fuel sulfur content of 0.4 gr/100 scf. This is consistent with determinations identified in the RBLC which contains limits ranging up to 2 gr/100 scf for similar units. Corresponding proposed short term SO_2 limits are 0.0013 lb/MMBtu with and without burner. Again, note that HTEC is not subject to BACT for SO_2.

BACT/BAT Analysis for Greenhouse Gases (GHGs) – CT/HRSG

For new "anyway" sources (such as HTEC), EPA intends to continue applying PSD BACT requirements to GHG emissions if the source emits or has the potential to emit at least 75,000 tpy GHGs. EPA acknowledges that the Supreme Court said the agency would need to justify a "de minimis" GHG emissions threshold above which BACT may be applied to "anyway" sources, but to ensure compliance with the Clean Air Act at present and until there are further developments at the D.C. Circuit, EPA will continue to apply the 75,000 tpy threshold; which was formally proposed on October 3, 2016 (FR Vol. 81 No. 191). As such, a BACT analysis for GHG emissions must be conducted using the same five-step, top-down approach used for other NSR pollutants according to EPA's guidance.

Identification of Potential Control Techniques

Potential GHGs control technologies identified for the CT with HRSG and duct burners include energy efficient and inherently lower-emitting processes/practices/designs, carbon capture and sequestration (CCS), and clean fuels.

Inherently Lower-Emitting Processes/Work Practices/Design – EPA specifies in various guidance documents that inherently lower-emitting processes are appropriate for consideration as available control alternatives. The guidance documents recommend several different methods for incorporating energy efficiency into a project including good combustion practices, utilizing more fuel-efficient equipment, employing a maintenance program, and using low-carbon fuels. Specific examples of inherently lower-emitting processes/work practices/design considered for the CT include fuel gas preheating, CT design, evaporative inlet air cooling or inlet fogging, periodic burner tuning, reduction in heat loss, and instrumentation and control. Energy efficiency design, practices and procedures considered for the HRSG include HRSG design, insulation, minimizing fouling of heat exchange surfaces, minimizing vented steam.

CCS – According to EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), "for the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants…" The document further states that "for these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."

CCS consists of the separation and capture of CO_2 from the flue gas, pressurization of the captured CO_2, transportation of the CO_2 as a fluid via pipeline, and injection and long-term geologic storage into deep

underground porous rock formations that hold the CO_2 where overlaying non-porous formations prevent it from migrating upward through the stratigraphy. Post-combustion systems are designed to separate CO_2 from the flue gas produced by the combustion process.

Clean Fuels – The CAA includes clean fuels in the definition of BACT; therefore, clean fuels should be considered as a potential control technology for GHG emissions. Fuels that reduce GHG emissions of a new source should be considered in a BACT analysis provided they do not redefine the source. For example, a proposed new coal plant should not have to consider switching fuels from coal to natural gas, as that would redefine the source. However, different types of coal may be considered to evaluate the benefits of combusting various types of coal in reducing GHG emissions.

Elimination of Technically Infeasible Control Options

Step 2 of the top-down BACT analysis is the elimination of technically infeasible options. EPA considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same type of source under review, or it is available and applicable to the source type under review. A control technology should also be considered technically available or applicable if it has been demonstrated on an exhaust stream with similar physical and chemical characteristics.

According to EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), although CCS is not in widespread use at this time, EPA generally considers CCS to be an "available" add-on pollution control technology for facilities emitting CO_2 in large amounts and industrial facilities with high-purity CO_2 streams. Assuming CCS has been included in Step 1 of the top-down BACT process for such sources, it now must be evaluated for technical feasibility in Step 2.

CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options)."

The guidance further explains, "The level of detail supporting the justification for the removal of CCS in Step 2 will vary depending on the nature of the source under review and the opportunities for CO_2 transport and storage. As with all top-down BACT analyses, cost considerations should not be included in Step 2 of the analysis, but can be considered in Step 4."

According to the applicant, "CCS technology has not been demonstrated on a full-scale power generation facility, and CCS technology is not currently commercially available for use on CTs and HRSGs. However, it is considered technically feasible, as required by U.S. EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011)."

Use of efficient combustion turbines, selecting a low-carbon fuel, and good combustion practices are considered technically feasible.

Ranking of Controls

Step 3 of the BACT review process ranks the technically feasible control technologies by control effectiveness. The remaining technically feasible options include CCS technology, high thermal or energy efficiency and the exclusive use of clean fuels. The energy efficiency must look at the high thermal efficiency design of the CT/HRSG system as well as various energy efficiency improvements throughout the facility. Based the information evaluated by HTEC as well as other publically available information evaluated by the Department, the technically feasible GHG control options and associated control efficiencies are ranked as follows:

1. Carbon Capture and Sequestration: 80-90%
2. Inherently Lower-Emitting Processes/Work Practices/Design: 10% - 50%
3. Clean Fuels: 0%

Evaluation of Most Effective Controls

According to the applicant, "The constituents of CCS technology (capture, compression, transport, and storage) have been determined to be technical feasible, but the overall cost per ton of CO_2 removed is not cost effective...In addition, there are unresolved issues with respect to CO_2 sequestration including the legal process for closing and remediating sequestration sites and liability for accidental releases from these sites."

As part of HTEC's economic analysis, considerations included other recent plan approvals (CPV Fairview, LLC PA-11-00536A; Shell Chemicals Appalachia, LLC/Shell Petrochemicals Complex PA-04-00740A), the 2012 Analysis of Cost and Benefits of CO_2 Sequestration on the U.S. Outer Continental Shelf prepared under DOE contract by ICF International, and a 2011 Report Cost and Performance of Carbon Dioxide Capture from Power Generation by the International Energy Agency (IEA). Based on the provided data, the Department has determined that CO_2 emissions reduction via capture, compression, transportation, and storage of CO_2 emissions from the combustion turbines and HRSG with duct burners is economically infeasible.

Furthermore, energy impacts from CCS implementation for regeneration of the capture medium, cleanup of impurities in the CO_2 gas, compression of the gas and injection into the ground will be severe and have been included in the economic analysis. Environmental impacts would include additional construction activities for CO_2 pipelines, injection wells and monitoring wells. The Department has determined that CCS exceeds BACT/BAT requirement standards and that BACT/BAT is high efficiency/good combustion practices.

Selection

Based on the above analysis, HTEC has proposed energy efficiency designs, practices, and procedures as GHG BACT for the CT/HRSG. Proposed CT energy efficiency designs, practices, and procedures include efficient turbine design, turbine inlet air cooling, periodic turbine burner tuning, reduction in heat loss (insulation of CT), and instrumentation and controls. Proposed HRSG energy efficiency designs, practices, and procedures include efficient heat exchanger design, reduction in heat lost (insulation of HRSG), minimizing fouling of heat exchanger surfaces, and minimizing steam venting and repair of steam leaks. Other practices include fuel gas preheating and efficient drain operation.

HTEC has proposed a GHG emission limit of 879 lb/MWh CO_2e (net) at base load with duct burner firing. HTEC will demonstrate compliance with this proposed average GHG limit on an annual basis by measuring/monitoring total natural gas consumption and electrical output during base load operations when

combusting natural gas without supplemental duct burner firing and during base load operations combusting natural gas with supplemental duct burner firing. The proposed limit is more stringent than any CO_2 limit under NSPS Subpart TTTT for electric generating units (of which the lowest is 1,000 lb/MWh CO_2 (gross)).

BAT Analysis for HAPs – CT/HRSG

According to Section 3.1.3.5 of EPA AP-42 Chapter 3.1 – *Stationary Gas Turbines* (April 2000), "Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emission data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines [presumed without post-combustion HAPs controls], formaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions." However, the notice of final rulemaking for 40 CFR Part 63 Subpart YYYY– *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* (*Federal Register*, March 5, 2004) states that "although numerous HAP may be emitted from combustion turbines, only a few account for essentially all the mass of HAP emissions from stationary combustion turbines" which include "formaldehyde, toluene, benzene, and acetaldehyde." The notice further states that "natural gas fired stationary combustion turbines do not emit metallic HAP."

Section 3.1.4.3 states that "Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions…CO catalysts are also being used to reduce VOC and organic HAPs emissions." The formation of carbon monoxide during the combustion process is also a good indicator of the expected levels of HAP emissions. In the notice of final rulemaking for 40 CFR Part 63 Subpart YYYY, EPA stated that "formaldehyde is an appropriate surrogate for the other organic HAP which are also controlled by an oxidation catalyst." Although the proposed CT/HRSG is not subject to Subpart YYYY since the facility is not considered major for HAPs, consistent with other plan approvals for similar sources, HCHO emissions will be limited to 91 ppbvd @ 15% O_2.

BAT Analysis for Ammonia – CT/HRSG

Ammonia will be used as a reagent in the SCR for NOx control. Ammonia slip is the ammonia that doesn't react in the SCR and exhausts into the atmosphere. The higher the NOx control efficiency usually requires greater amounts of ammonia which results in higher levels of ammonia slip. Ammonia to NOx molar ratios greater than one-to-one are necessary to achieve high NOx removal efficiencies due to imperfect mixing and other reaction limitations. BAT has been determined to be good combustion practices such that the exhaust gas temperature stays within the designed temperature range of the SCR and injecting the proper amount of ammonia. HTEC has proposed an ammonia slip emission limit of 5.0 ppmvd at 15% O_2. Although HTEC is not subject to BACT for ammonia, the proposed emission limit is consistent with similar sources found in the RBLC.

Based on the above analysis, the following table lists a summary of the LAER/BACT/BAT analysis for the CT/HRSG:

Table 4: CT/HRSG LAER/BACT/BAT Summary

Pollutant	Control Technology	Emission Limit
NOx	SCR and DLN	2.0 ppmvd @ 15% O_2
CO	Oxidation Catalyst and Good Combustion Practices	2.0 ppmvd @ 15% O_2
VOC	Oxidation Catalyst and Good Combustion Practices	1.0 ppmvd @ 15% O_2 w/o duct burner
		2.0 ppmvd @ 15% O_2 w/ duct burner
PM	Low Sulfur Fuel and Good Combustion Practices	0.0071 lb/MMBtu w/o duct burner
		0.00718 lb/MMBtu w/ duct burner
PM_{10}	Low Sulfur Fuel and Good Combustion Practices	0.0071 lb/MMBtu w/o duct burner
		0.00718 lb/MMBtu w/ duct burner
$PM_{2.5}$	Low Sulfur Fuel and Good Combustion Practices	0.0071 lb/MMBtu w/o duct burner
		0.00718 lb/MMBtu w/ duct burner
H_2SO_4	Low Sulfur Fuel	0.0007 lb/MMBtu
GHG	Energy Efficient Design and Good Combustion Practices	879 lbs CO_2/MWh (net)
HCHO	Oxidation Catalyst and Good Combustion Practices	91 ppbvd @ 15% O2
NH_3	Good Engineering Practices	5.0 ppmvd @ 15% O2

LAER/BACT/BAT Analysis - Auxiliary Boiler

<u>NOx LAER Analysis – Auxiliary Boiler</u>

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, ultra-low NOx burners along with an emission limit of 0.011 lb/MMBtu has been determined to be LAER for the proposed auxiliary boiler. Note that this emission limit is based upon a NOx exhaust concentration of 9 ppmvd @ 3% O_2.

<u>CO BACT Analysis – Auxiliary Boiler</u>

Potentially available control options for reducing VOC emissions from natural gas-fired auxiliary boilers include combustion controls and post-combustion controls (i.e. oxidation catalyst). Other recent plan approvals for similar sources have determined oxidation catalyst to be technically infeasible. However, HTEC determined oxidation catalyst can potentially be technically feasible and but determined that it is economically infeasible.

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, good combustion and operating practices along with an emission limit of 0.037 lb/MMBtu has been determined to be appropriate LAER for the proposed auxiliary boiler.

<u>VOC LAER Analysis – Auxiliary Boiler</u>

Potentially available control options for reducing CO emissions from natural gas-fired auxiliary boilers include combustion controls and post-combustion controls (i.e. oxidation catalyst); however, oxidation catalyst was determined to be economically infeasible in the CO BACT analysis.

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, good combustion and operating practices along with an emission limit of 0.003 lb/MMBtu has been determined to be appropriate BACT for the proposed auxiliary boiler.

PM/PM_{10}/ $PM_{2.5}$ BACT Analysis – Auxiliary Boiler

Potentially available control options for reducing PM emissions from natural gas-fired auxiliary boilers include low-sulfur fuels, fabric filter baghouse, electrostatic precipitator, wet electrostatic precipitator, wet scrubber, and good combustion practices.

Similar to the CT, due to the inherently low total PM emissions rates associated with low-ash and low-sulfur fuels in auxiliary boilers, add-on filtration or collection devices would exhibit very low control efficiencies, and as a result, high cost to control efficiency ratio. As such, post-combustion control is considered infeasible.

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, combustion of low sulfur pipeline quality natural gas and good combustion practices, along with an emission limit of 0.0074 lb/MMBtu on a 3-hour averaging period has been determined to be appropriate BACT for the proposed auxiliary boiler.

H_2SO_4 BACT and SO_2 BAT Analysis – Auxiliary Boiler

Potentially available control techniques for reducing SO_2 and H_2SO_4 include use of low sulfur fuel and post-combustion add-on controls to reduce SO_2 and H_2SO_4 such as flue gas desulfurization (FGD) scrubber and dry sorbent injection.

Similar to the CT, due to the low concentration of H_2SO_4 and SO_2 in the exhaust gas, neither the FGD scrubber nor dry sorbent injection would provide measurable emission reduction. Due to the boiler size and minimal potential emissions of SO_2 from the auxiliary boiler, post-combustion controls have been determined to be technically infeasible.

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, combustion of pipeline quality natural gas and good combustion practices has been determined to be appropriate for control of H_2SO_4 and SO_2 from the proposed auxiliary boiler. The proposed emission limit for H_2SO_4 is 0.0001 lb/MMBtu and 0.0058 lb/MMBtu for SO_2.

GHG BACT Analysis – Auxiliary Boiler

As discussed previously for new "anyway" sources, EPA intends to continue applying PSD BACT requirements to GHG emissions if the source emits or has the potential to emit at least 75,000 tpy GHGs. Of the six GHGs included by definition in §52.21(b)(49)(i), the GHGs emitted from combustion sources include only carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4).

Potentially available control options for reducing GHG emissions from natural gas-fired auxiliary boiler include efficient boiler design, cleaner fuels, and good combustion practices. The applicant has not identified any technically feasible add-on control technology to reduce GHG emissions from the auxiliary boiler. As previously discussed, CCS may be considered technically feasible for the facility, but has been determined to be economically infeasible.

Based on the control technology evaluation and review of the RBLC and other recent plan approvals, efficient boiler design, cleaner fuels, and good combustion practices have been determined to be BACT for the auxiliary boiler. An annual BACT emissions limit for GHG from the auxiliary boiler will not be imposed; however, annual GHG emissions will be calculated using appropriate 40 CFR Part 98 emissions factors and counted toward the annual facility-wide GHG emissions limit.

LAER/BACT/BAT Analysis – Fuel Gas Heater

To determine LAER and BACT for the 6.4 MMBtu/hr fuel gas heater, the applicant queried the RBLC database for industrial sized boilers and furnaces between less than 100 MMBtu/hr heat input firing natural gas only. Determinations were obtained for the last 10 years and are summarized in Table D-3 of Appendix D of the application.

No add-on controls were specified in the RBLC for comparably sized units. Additionally, add-on controls were found to be neither technically feasible due to the type and size of the heater nor economically feasible due to the minimal annual emissions rates. LAER/BACT/BAT for the dew point heater has been determined to be firing of pipeline quality natural gas and good combustion practices. Table 5 below summarizes the proposed emission limits for the dew point heater.

Table 5: 6.4 MMBtu/hr Fuel Gas Heater LAER/BACT/BAT Summary

Pollutant	Emission Rate	Units	Control Technology
NOx	0.011	lb/MMBtu	GCP
VOC	0.0054	lb/MMBtu	GCP
CO	0.037	lb/MMBtu	GCP
PM	0.0074	lb/MMBtu	GCP, low sulfur fuel
SO_2	0.0058	lb/MMBtu	GCP, low sulfur fuel
GHG	3,283	tpy CO2e	GCP

GCP = good combustion practices

LAER/BACT/BAT Analysis – Emergency Diesel Engines

HTEC has proposed two (2) diesel-fired engines; one (1) 2,682 bhp emergency generator and one (1) 422 bhp fire-water pump. Each unit will be used for emergency use only (except for periodic readiness testing and maintenance) and will meet the applicable NSPS Subpart IIII requirements. This includes use of diesel fuel meeting the requirements of 40 CFR 80.510(b) for non-road diesel fuel (i.e. maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35% by volume). Each engine will also be required to be equipped with a nonresettable hour meter and to maintain records of fuel usage on a 12-month rolling basis. Consistent with NSPS IIII, since each engine will be certified to meet the applicable emissions standards, testing will not be required except if the engines are not installed, configured, operated, or maintained according to the manufacturer's emission-related written instructions, or emission-related settings are changed in a way that is not permitted by the manufacturer; however the Department may require testing if there is reason to believe emissions are, or may be, in excess of the limits established in this plan approval.

For the proposed emergency engines, HTEC conducted a BAT/BACT/LAER analysis for NO_2/NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, SOx and GHGs. In general, fitting each of the engines with add-on controls for each of the subject pollutants has been determined to be technically infeasible due to the intermittent and limited

operational duration (less than 100 hours per year) of each unit. Beyond the technical infeasibility, the minimal potential emissions associated with sources operated for limited operational periods renders add-on controls economically infeasible on a cost per ton basis.

NOx/VOC LAER/BACT Analysis – Emergency Diesel Engines

The LAER/BACT determination for the emergency generator is good combustion practices and certification to an emission standard for NOx + NMHC of 6.4 g/kW-hr which is equivalent to the applicable NSPS Subpart IIII emission standard. The LAER/BACT determination for the fire pump engine is good combustion practices and certification to an emission standard for NOx +NMHC of 3.0 g/bhp-hr which is which is equivalent to the NSPS Subpart IIII emission standard of 4.0 g/kW-hr (3.0 g/bhp-hr). Based upon the proposed emission rates and the operational limitation (100 hours/year), HTEC has determined that post combustion controls (i.e. SCR, NSCR) are economically infeasible for emergency engines. The proposed limits are consistent with NSPS IIII, other recent plan approvals, and review of the RBLC.

The underlying emissions standards for NO_X+NMHC in Subpart IIII—when previously NO_X only—support the negligibility of NMHC and VOC (a subset of NMHC) emissions from certified diesel engines. Therefore, in lieu of imposing a limitation and emissions testing for VOC, the VOC LAER for the emergency engines will achieved by installing engines certified to the applicable Tier emissions standard

CO BACT Analysis – Emergency Diesel Engines

Table 4 in 40 CFR 60.4219 lists the emission standards for the 422 bhp stationary firewater pump engine to be certified to meet. The NSPS certification rate of 2.6 g/bhp-hr is proposed as a BACT derived emission limit. Although add-on CO controls are feasible for this size engine, the fact that this is an emergency engine limited to 100 hr/yr for maintenance and testing make add-on controls economically infeasible.

The proposed 2,682 bhp emergency generator engine will meet the Tier II emissions limits of NSPS Subpart IIII shown in Table 1 of 40 CFR 89.112. The CO Tier II emissions limit of 3.5 g/kWp-hr is proposed as BACT.

PM/PM_{10}/ $PM_{2.5}$ BACT Analysis – Emergency Diesel Engines

Add-on controls for the emergency diesel engines for PM, PM_{10}, and $PM_{2.5}$ has been determined to be technically feasible, however due to the intermittent and limited operational duration (less than 100 hours per year of each unit) and the minimal potential emissions, add-on controls have been determined to be economically infeasible on a cost per ton basis and the installation of such controls would result in negligible environmental benefit. Therefore, PM, PM_{10}, and $PM_{2.5}$ BAT/BACT has been determined to be good combustion practices and proper operation and maintenance including installation of engines certified to the applicable Subpart IIII emissions standards and using ULSD. The applicable Tier standard of 0.15 g/bhp-hr is proposed as a limit for the fire water engine and 0.20 kW/bhp-hr for the emergency engine.

H_2SO_4 and SO_2 BACT/BAT Analysis – Emergency Diesel Engines

There are no post-combustion control technologies available for control of H_2SO_4 and SO_2 from emergency diesel engines. HTEC has proposed good combustion practices and use of ULSD. In lieu of establishing H_2SO_4 and SO_2 emissions limitations, these pollutants will be limited by a fuel sulfur content of 15 ppm for non-road fuel specified in 40 CFR §80.510(b) pursuant to 40 CFR Part 60 Subpart IIII.

GHG BACT/BAT Analysis – Emergency Diesel Engines

There is currently no technically feasible add-on control technology to reduce GHG emissions from the firewater pump or emergency generator engines. HTEC is proposing to limit GHG emissions from these sources by incorporating good combustion practices and limiting the hours of operation. The emergency engines will be maintained in accordance with the manufacturer's specifications.

BACT/BAT Analysis – Cooling Tower

The proposed cooling tower is a multi-cell, mechanical induced draft cooling tower that will be used to reject heat from cooling water for the condensate system and other plant uses. The proposed cooling tower has eight (8) cells with a water circulation rate of 114,420 gallons per minute (gpm). Particulate matter is emitted from wet cooling towers because the water circulating in the tower contains small amounts of dissolved solids (e.g. calcium, magnesium, etc.) that crystallize and form airborne particles as the water drift leaves the cooling tower and evaporates.

Potentially available control options for reducing particulate matter emissions from mechanical draft cooling towers include options to minimize dissolved solids in the cooling water and add-on controls such as advanced drift eliminators. Drift eliminators control PM emissions by capturing water droplets from the cooling tower exhaust using inertial separation principles.

HTEC has proposed high efficiency drift eliminators with a drift rate of 0.0005 percent as BACT/BAT for PM, PM_{10}, and $PM_{2.5}$ emissions from the cooling tower. HTEC will be required to continually monitor and record the circulating water TDS to ensure continued compliance with the proposed emission rates. This determination is consistent with other recent plan approvals and sources identified in the RBLC.

BACT/BAT Analysis – Circuit Breakers

Sulfur hexafluoride (SF_6) is a greenhouse gas with a global warming potential (GWP) of 22,800 commonly used in circuit breaker as a high voltage insulator and circuit-interrupting medium. Progress has been made in finding SF_6 alternatives for use in low and medium voltage applications; however, the inertness and dielectric properties of SF_6 are such that no effective substitutes are known for high voltage applications at this time. Therefore, non-SF_6 circuit breakers have been determined to be technically infeasible.

In order to control potential leaks to the maximum extent possible, HTEC has proposed to use state-of-the-art circuit breaker technology with a totally enclosed pressure system to minimize leaks, as well as the implementation of density alarm leak detection to ensure that SF_6 leaks are repaired as soon as possible. Based upon review of the RBLC and other recent plan approvals, circuit breakers with leak detection equipment that alerts the operator when 10% of the SF_6 by weight has escaped from any breaker will be required.

BACT/BAT GHG Analysis – Fugitive Emissions from Natural Gas Piping Components

Fugitive emissions result from natural gas leaks from valves, flanges, connectors, open-ended valves/lines, etc. Natural gas delivered to the facility will have an average maximum supply pressure of 1,000 psig and average minimum supply pressure of 650 psig. In determining BAT for component leaks, the Department considered other recent plan approvals for similar facilities, and natural gas transmission and compression facilities which

include similar components. Although the proposed facility has fewer components than a transmission or compression facility, it will have similar emission points on the high pressure gas supply line.

In order to minimize fugitive emissions from high pressure component leaks, and consistent with other recent BACT/BAT determinations for similar sources, the applicant will be required to perform a monthly leak detection and repair program which includes audible, visual, and olfactory (AVO) inspections. AVO incorporates operator leak detection by sound, sight, and smell, and may also incorporate techniques such as detection devices, or the "soap bubble" method where a soap and water solution is applied to piping components whereby the production of bubbles or lack thereof determines the presence of absence of a leak.

Pursuant to the definition of best available control technology in 40 CFR §52.21(b)(12), due to technological limitations on measurement of leaks and quantifying the effectiveness of a leak monitoring and repair program, the Department has determined that the imposition of an emissions standard applicable to equipment leaks is infeasible, and has prescribed the above work practice and operational standards to satisfy the requirement for the application of best available control technology. Fugitive GHG emissions will be calculated for all natural gas piping components on an annual basis to demonstrate compliance with the annual facility-wide emissions limit.

Air Quality Modeling Analysis

Concurrently with its application for plan approval, HTEC submitted a source impact analysis (modeling analysis) as required by 40 CFR §52.21(k). The required analysis must demonstrate that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions (including secondary emissions), would not cause or contribute to air pollution in violation of any national ambient air quality standard in any air quality control region or any applicable maximum allowable increase over the baseline concentration in any area.

According to the *Summary of Air Quality Analysis for Prevention of Significant Deterioration* ("summary") dated September 11, 2017, from the Department's Air Quality Modeling Section, the Department's technical review concluded that, "In accordance with 40 CFR §52.21(k), HTEC's source impact analyses demonstrate that the Hill Top Energy Center's emissions would not cause or contribute to air pollution in violation of the NAAQS for CO, NO_2, PM-2.5, or PM-10. Additionally, HTEC's source impact analyses demonstrate that the Hill Top Energy Center's emissions would not cause or contribute to air pollution in violation of the Class II or Class I PSD increments for NO_2, PM-2.5, or PM-10.

In accordance with 40 CFR § 52.21(l), HTEC's estimates of ambient concentrations are based on applicable air quality models, data bases, and other requirements specified in the EPA's *Guideline on Air Quality Models* as well as the EPA's relevant air quality modeling policy and guidance.

In accordance with 40 CFR § 52.21(m), HTEC provided an analysis of existing ambient air quality in the area that the Hill Top Energy Center would affect which included existing representative monitoring data for CO, NO_2, PM-2.5, and PM-10. HTEC was exempted from the requirements of 40 CFR § 52.21(m) for H_2SO_4.

In accordance with 40 CFR § 52.21(n), HTEC provided all information necessary to perform the air quality analyses required by the PSD regulations, including all dispersion modeling data necessary to estimate the air quality impacts of HTEC's facility.

In accordance with 40 CFR § 52.21(o), HTEC provided additional impact analyses of the impairment to visibility, soils, and vegetation that would occur as a result of the Hill Top Energy Center and general commercial, residential, industrial, and other growth associated with the Hill Top Energy Center.

In accordance with 40 CFR § 52.21(p), written notice of the proposed Hill Top Energy Center has been provided to the FLMs of nearby Federal Class I areas as well as initial screening calculations to demonstrate that the Hill Top Energy Center's emissions would not adversely impact AQRVs and visibility in nearby Federal Class I areas." The facility is proposed to be located within 300 km of four Class I areas:

- Otter Creek Wilderness (approximately 95 km)
- Dolly Sods Wilderness (approximately 106 km)
- Shenandoah National Park (approximately 182 km)
- James River Face (approximately 255 km)

On March 3, 2017, the Department received an email from Melanie Pitrolo of the Forest Service stating that, "...After reviewing the permit application, it is not anticipated that emissions from the proposal will cause or contribute to adverse impacts of air quality related values at Forest Service Class I Areas. Therefore, we will not be requesting an AQRV modeling analysis be included as part of the application. Should the nature of the project change such that emissions increase (either short term or annual) please let me know so that I may reevaluate this determination..."

On April 3, 2017, the Department received an email from Andrea Stacy of the NPS stating that, "...no Class I analysis is necessary for the proposed Hilltop energy facility..."

Sources, Control Devices, and Emissions

Emission were calculated by the applicant for the proposed natural gas-fired CT/HRSG based upon the turbine manufacturer's emissions data and recommendations, SCR control efficiency, oxidation catalyst control efficiencies, AP-42 Chapters 1.4 and 3.1 emission factors, and 40 CFR Part 98 Subpart C emission factors. Emissions were calculated at 8,760 hours at full load and considering the maximum allowable startup/shutdown time of 162 hours to determine the worst case scenario for each pollutant. Potential emissions account for the maximum hours of operation of the duct burners of 8,760 hours per year. SO_2, H_2SO_4, and PM (including PM_{10} and $PM_{2.5}$ and condensable portions) were calculated by the applicant based upon the sulfur content of the natural gas. Short term emissions were calculated based upon the maximum sulfur content of 2.0 gr/100 scf and annual emissions were calculated based upon the average sulfur content of 0.4 gr/100 scf (based upon the tariff sheet). NOx emissions during normal operation will be controlled by selective catalytic reduction. VOC and CO emissions will be controlled by oxidation catalysts. The oxidation catalysts are also expected to control HCHO emissions however the manufacturer has not provided a guaranteed control efficiency.

Other potential sources at this facility include a 42 MMBtu/hr natural gas-fired auxiliary boiler; 6.4 MMBtu/hr fuel gas heater; 2,682 hp diesel-fired emergency generator; 422 hp diesel-fired fire pump engine; emissions from the cooling tower; fugitive emissions from natural gas piping component leaks; and fugitive SF_6 emissions from the circuit breakers. Detailed emission calculations for all pollutants and operating scenarios (e.g. startup/shutdown) are included in Appendix C of this plan approval application. The Department determined the applicant's emission calculations are acceptable. Table 6 below summarizes the facility-wide PTE.

Table 6: Facility-Wide PTE (tpy)

Pollutant	CT/HRSG/Duct Burners [a]	Auxiliary Boiler 42 MMBtu/hr [b]	Fuel Gas Heater 6.4 MMBtu/hr	Emergency Generator [c]	Fire Pump Engine [c]	Cooling Tower	Piping Components	Circuit Breakers	Facility-Wide
NOx	169.36	1.99	0.31	1.32	0.13	-	-	-	**173.10**
CO	151.41	6.81	1.04	0.77	0.12	-	-	-	**160.14**
VOC	59.31	0.55	0.15	0.09	0.01	-	-	-	**60.11**
HCHO	5.77	0.013	0.002	7.41E-05	1.74E-04	-	-	-	**5.78**
Hexane [d]	-	7.52	-	-	-	-	-	-	**7.52**
Total HAPs	18.38	0.022	0.003	0.004	0.001	-	-	-	**18.41**
Total PM	105.28	1.36	0.21	0.044	0.007	5.02	-	-	**111.92**
Total PM_{10}	105.28	1.36	0.21	0.044	0.007	3.35	-	-	**110.25**
Total $PM_{2.5}$	105.28	1.36	0.21	0.044	0.007	1.28	-	-	**108.18**
H_2SO_4	13.04	0.02	0.003	0.001	0.003	-	-	-	**13.06**
SO_2	23.12	0.21	0.03	0.002	0.04	-	-	-	**23.42**
NH_3	136.46	-	-	-	-	-	-	-	**136.46**
GHGs (as CO_2e)	2,298,774	21,891	3,336	153	24	-	61	111	**2,324,350**

[a] CT/HRSG/Duct Burner emissions include startup and shutdown and a maximum duct burner operation of 8,760 hours/year.
[b] Auxiliary boiler emissions based upon a maximum operation of 8,760 hours/year.
[c] Emergency diesel engine emissions based upon operation of 100 hours/year.
[d] Hexane is the single highest HAP.

Conclusions and Recommendations

HTEC has demonstrated that the proposed natural gas-fired combined cycle power plant located in Cumberland Township, Greene County meets the requirements of 40 CFR Part 52.21 (related to Prevention of Significant Deterioration), 25 Pa. Code Subchapter E (related to New Source Review), and the Best Available Technology requirements of 25 Pa. Code Chapter 127. HTEC has also demonstrated that the proposed facility will not cause or contribute to air pollution in violation of the NAAQS, will not impair visibility, soils, and vegetation, and will not adversely affect air quality related values (AQRV), including visibility, in federal Class I areas. Therefore, I recommend issuance of PA-30-00233B for a term of three (3) years to reasonably accommodate construction of a facility of this size with the following special conditions.

Special Conditions

Site Level Requirements

RESTRICTIONS

1. No person may permit air pollution as that term is defined in the act [25 Pa. Code §121.7].

2. The permittee may not permit the emission into the outdoor atmosphere of a fugitive air contaminant contrary to 25 Pa. Code §123.1.

3. The permittee may not permit fugitive particulate matter to be emitted into the outdoor atmosphere from a source specified in §123.1(a)(1)–(9) if the emissions are visible at the point the emissions pass outside the permittee's property [25 Pa. Code §123.2].

4. The permittee may not allow the emission into the outdoor atmosphere of any malodorous air contaminants from any source, in such a manner that the malodors are detectable outside the permittee's property [25 Pa. Code §123.31].

5. Limitations of visible air contaminants shall not apply to a visible emission in any of the following instances [25 Pa. Code §127.12b]:

   (a) When the presence of uncombined water is the only reason for failure of the emission to meet the limitations.
   (b) When the emission results from the operation of equipment used solely to train and test persons in observing the opacity of visible emissions.
   (c) When the emission results from sources specified in §123.1(1)–(9).
   (d) N/A

6. The emissions from all sources and associated air cleaning devices installed and operated under this authorization shall not exceed any of the following on a 12-month rolling sum basis:

   (a) Nitrogen Oxides (NOx): 173.10 tpy
   (b) Carbon Monoxide (CO): 160.14 tpy
   (c) Sulfur Dioxide (SO_2): 23.42 tpy
   (d) Volatile Organic Compounds (VOC): 60.11 tpy
   (e) Particulate Matter (PM): 111.92 tpy
   (f) Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}): 110.25 tpy
   (g) Particulate Matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$): 108.18 tpy
   (h) Sulfuric Acid Mist (H_2SO_4): 13.06 tpy
   (i) Ammonia (NH_3): 136.46 tpy
   (j) Total Hazardous Air Pollutants (HAPs): 18.41 tpy
   (k) Formaldehyde: 5.78 tpy
   (l) Greenhouse Gases, expressed as Carbon Dioxide Equivalent (CO_2e): 2,324,350 tpy

TESTING REQUIREMENTS

7. If, at any time, the Department has cause to believe that air contaminant emissions from the sources listed in this plan approval may be in excess of the limitations specified in, or established pursuant to this plan approval or the permittee's operating permit, the permittee may be required to conduct test methods and procedures deemed necessary by the Department to determine the actual emissions rate. Such testing shall be conducted in accordance with 25 Pa. Code Chapter 139, where applicable, and in accordance with any restrictions or limitations established by the Department at such time as it notifies the company that testing is required [25 Pa. Code §127.12b].

8. Performance testing shall be conducted as follows [25 Pa. Code §127.12b and §139.11]:

   (a) The Permittee shall submit two hard copies and one electronic copy of a pre-test protocol to the Department for review at least 60 days prior to the performance of any EPA reference method stack test. All proposed performance test methods shall be identified in the pre-test protocol and approved by the Department prior to testing.

   (b) The Permittee shall notify the Regional Air Quality Manager and Division of Source Testing and Monitoring at least 15 days prior to any performance test so that an observer may be present at the time of the test. This notification may be sent by email. Notification shall not be made without prior receipt of a protocol acceptance letter from the Department.

   (c) Two (2) hard copies and one (1) electronic copy a complete test report shall be submitted to the Department no later than 60 calendar days after completion of the on-site testing portion of an emission test program.

   (d) Pursuant to 25 Pa. Code Section 139.53(b) a complete test report shall include a summary of the emission results on the first page of the report indicating if each pollutant measured is within permitted limits and a statement of compliance or non-compliance with all applicable permit conditions. The summary results will include, at a minimum, the following information:

      (1) A statement that the owner or operator has reviewed the report from the emissions testing body and agrees with the findings.
      (2) Permit number(s) and condition(s) which are the basis for the evaluation.
      (3) Summary of results with respect to each applicable permit condition.
      (4) Statement of compliance or non-compliance with each applicable permit condition.

   (e) Pursuant to 25 Pa. Code § 139.3 all submittals shall meet all applicable requirements specified in the most current version of the Department's Source Testing Manual.

   (f) All testing shall be performed in accordance with the provisions of Chapter 139 of the Rules and Regulations of the Department of Environmental Protection.

   (g) Pursuant to 25 Pa. Code Section 139.53(a)(1) and 139.53(a)(3) all hard copy submittals shall be sent to the Pennsylvania Department of Environmental Protection, Air Quality Program, 400 Waterfront Drive, Pittsburgh, PA 15222 with deadlines verified through document postmarks. Electronic submittals shall be sent to RA-epstacktesting@pa.gov. Alternatively, electronic copies may be provided on a CD along with hard copy submittals.

(h) The permittee shall ensure all federal reporting requirements contained in the applicable subpart of 40 CFR are followed, including timelines more stringent than those contained herein. In the event of an inconsistency or any conflicting requirements between state and the federal, the most stringent provision, term, condition, method or rule shall be used by default.

MONITORING REQUIREMENTS

9. Visible emissions may be measured using either of the following [25 Pa. Code §123.43]:

   (a) A device approved by the Department and maintained to provide accurate opacity measurements.
   (b) Observers, trained and qualified to measure plume opacity with the naked eye or with the aid of devices approved by the Department.

10. The permittee shall conduct a facility-wide inspection for the presence of any visible stack emissions, fugitive emissions, and any potentially objectionable odors at the property line at a minimum of once each operating day, during daylight hours, and while the sources are operating. If visible stack emissions, fugitive emissions, and/or potentially objectionable odors are apparent, the permittee shall take corrective action. Records of each inspection shall be maintained in a log and at the minimum include the date, time, name and title of the observer, along with any corrective action taken as a result [25 Pa. Code §127.12b].

11. Periodic monitoring shall be conducted as follows [25 Pa. Code §127.12b]:

    (a) The permittee shall submit two hard copies and one electronic copy of a one-time protocol to the Department for review for the use of a portable analyzer and may repeat portable analyzer testing without additional protocol approvals provided that the same method and equipment are used.

RECORDKEEPING REQUIREMENTS

12. The permittee shall maintain the following comprehensive and accurate records [25 Pa. Code §127.12b]:

    (a) Facility-wide emissions on a 12-month rolling basis for NOx, CO, SOx, VOC, PM, PM10, PM2.5, H2SO4, NH3, HAPs, HCHO, hexane, and CO2e.
    (b) Amount of fuel used by each combustion unit, engine, and turbine on a 12-month rolling basis.
    (c) Hours of operation of each air contamination source on a 12-month rolling basis.
    (d) Results of facility-wide inspections including the date, time, name, and title of the observer, along with any corrective action taken as a result.
    (e) A description of testing methods, results, all operating data collected during tests, and a copy of the calculations performed to determine compliance with emission standards
    (f) Copies of the manufacturer's recommended maintenance schedule for each air contamination source and air cleaning device.
    (g) All maintenance performed on each air contamination source and air cleaning device.
    (h) Copies of the current, valid purchase contract, tariff sheet, or transportation contract obtained from the natural gas supplier with the sulfur content of the natural gas.
    (i) Results of the annual natural gas sulfur content analyses.
    (j) Amount of sulfur hexafluoride (SF6) dielectric fluid added to each circuit breaker unit on a monthly basis.

(k) The date and time that each alarm associated with the circuit breaker is activated, the corrective action taken to remedy the problem associated with each alarm, and the date the corrective action remedied the problem.

13. All logs and required records shall be maintained on site, or at an alternative location acceptable to the Department, for a minimum of five years and shall be made available to the Department upon request [25 Pa. Code §127.12b].

REPORTING REQUIREMENTS

14. Annual emissions reporting shall be conducted as follows [25 Pa. Code §127.12b and §135.3]:

(a) The permittee shall submit by March 1 of each year, a source report for the preceding calendar year for all sources authorized under this plan approval. The report shall include information for all previously reported sources, new sources which were first operated during the preceding calendar year and sources modified during the same period which were not previously reported.

(b) The source report; in a form as the Department may prescribe; for classes or categories of sources; shall show the actual emissions of carbon monoxide (CO), oxides of nitrogen (NOx), particulate matter less than 10 micrometers in diameter (PM10), particulate matter less than 2.5 micrometers in diameter (PM2.5), sulfur dioxide (SO2), volatile organic compounds (VOC), total hazardous air pollutants (HAP), speciated individual HAP emissions (per the Department's Emissions Inventory Reporting Instructions), sulfuric acid mist (H2SO4), ammonia (NH3) and greenhouse gases, expressed as CO_2e for each reporting period. A description of the method used to calculate the emissions and the time period over which the calculation is based shall be included. The statement shall also contain a certification by a company officer or the plant manager that the information contained in the statement is accurate.

(c) A source owner or operator may request an extension of time from the Department for the filing of a source report, and the Department may grant the extension for reasonable cause.

15. Malfunction reporting shall be conducted as follows [25 Pa. Code §127.12b]:

(a) The Owner/Operator shall report each malfunction that occurs at this Facility that poses an imminent and substantial danger to the public health and safety or the environment or which it should reasonably believe may result in citizen complaints to the Department. For purpose of this condition a malfunction is defined as any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment or source to operate in a normal or usual manner that may result in an increase in the emission of air contaminants. Examples of malfunctions may include, but are not limited to: large dust plumes, heavy smoke, a spill or release that results in a malodor that is detectable outside the property of the person on whose land the source is being operated.

(b) When the malfunction poses an imminent and substantial danger to the public health and safety, potential harm to the environment, the permittee shall report the incident to the Department within one hour of discovery. The permittee shall also notify the Department within one hour, when corrective measures have been accomplished.

All other malfunctions that must be reported under subsection (a) shall be reported to the Department no later than the next business day.

(c) Initial reporting of the malfunction shall identify the following items to the extent known:

(1) Name and location of the facility;
(2) Nature and cause of the malfunction;
(3) Time when the malfunction or breakdown was first observed;
(4) Expected duration of increased emissions; and
(5) Estimated rate of emissions.

(d) Malfunctions shall be reported to the Department by e-mail (addresses will be provided by the Department) or at the following address:

PA DEP
Office of Air Quality
400 Waterfront Drive
Pittsburgh, PA 15222-4745
412-442-4000

(e) If requested by the Department, the permittee shall submit a full written report to the Department including final determinations of the items identified in (c) and the corrective measures taken on the malfunction. The report shall be submitted within 15 days of the Department's request or accomplishing corrective measures, whichever is later.

16. The Facility is subject New Source Performance Standards from 40 CFR Part 60 Subparts Dc, IIII, KKKK, and TTTT. In accordance with 40 CFR §60.4, copies of all requests, reports, applications, submittals, and other communications regarding the affected sources shall be forwarded to the Department at the address listed below unless otherwise noted [40 CFR §60.4].

Pennsylvania Department of Environmental Protection
Air Quality Program
400 Waterfront Drive
Pittsburgh, PA 15222-4745

Copies of all requests, reports, applications, submittals, and other communications shall also be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI) accessible at https://cdx.epa.gov/ unless electronic reporting is not available, in which case a copy shall be sent to the following address:

Director
Air Protection Division
Mail Code 3AP00
U.S. EPA, Region III
1650 Arch Street
Philadelphia, PA 19103-2029

17. The Facility is subject National Emission Standards for Hazardous Air Pollutants from 40 CFR Part 63 Subpart ZZZZ. In accordance with 40 CFR §63.13, copies of all requests, reports, applications, submittals,

and other communications regarding the affected sources shall be forwarded to the Department at the address listed below unless otherwise noted.

Pennsylvania Department of Environmental Protection
Air Quality Program
400 Waterfront Drive
Pittsburgh, PA 15222-4745

Copies of all requests, reports, applications, submittals, and other communications shall also be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI) accessible at https://cdx.epa.gov/ unless electronic reporting is not available, in which case a copy shall be sent to the following address:

Director
Air Protection Division
Mail Code 3AP00
U.S. EPA, Region III
1650 Arch Street
Philadelphia, PA 19103-2029

WORK PRACTICE REQUIREMENTS

18. The permittee shall construct, operate, and maintain all air contamination sources and air cleaning devices authorized under this Plan Approval in accordance with the manufacturer's specifications and recommended maintenance schedules [25 Pa. Code § 127.12b].

ADDITIONAL REQUIREMENTS

19. In accordance with 25 Pa. Code § 127.201 through § 127.217, the permittee shall secure 200 tons of NOx emission reduction credits (ERCs) and 70 tons of VOC ERCs. The ERCs shall be properly generated, certified by the Department, and processed through the registry no later than the date approved by the Department for commencement of operation of the proposed facility. This facility may not commence operation until the required emissions reductions are certified and registered by the Department and included in a plan approval. [25 Pa. Code § 127.12b].

20. The permittee shall comply with all applicable requirements of New Source Performance Standards from 40 CFR Part 60 Subparts Dc, IIII, KKKK, and TTTT and National Emission Standards for Hazardous Air Pollutants from 40 CFR Part 63 Subpart ZZZZ [25 Pa. Code § 127.12b].

21. The permittee shall comply with all applicable requirements under 40 CFR Parts 72, 73, and 75 related to the Acid Rain Program [25 Pa. Code § 127.12b].

22. The permittee shall comply with the applicable requirements of the Cross-State Air Pollution Rule (CSAPR) codified in 40 CFR Part 97 Subparts AAAAA-CCCCC, as applicable, by the compliance dates therein specified. [25 Pa. Code §127.12b]

23. The permittee shall comply with all applicable requirements under 40 CFR Part 98 related to the Mandatory Greenhouse Gas Reporting Rule [25 Pa. Code § 127.12b].

24. This plan approval is to allow construction and temporary operation of a combined cycle natural gas-fired power plant by Hill Top Energy Center, LLC located in Cumberland Township, Greene County [25 Pa. Code § 127.12b].

25. Air contamination sources and air cleaning devices authorized for construction and temporary operation under this plan approval include [25 Pa. Code § 127.12b]:

- One (1) 3,509 MMBtu/hr General Electric International, Inc. (GE) model no. GE 7HA.02 natural gas-fired combined cycle combustion turbine equipped with a heat recovery steam generator (HRSG) with supplemental 981.4 MMBtu/hr HHV natural gas fired duct burners; controlled by selective catalytic reduction and oxidation catalyst.
- One (1) 42 MMBtu/hr HHV natural gas-fired auxiliary boiler.
- One (1) 6.4 MMBtu/hr HHV natural gas-fired fuel gas heater.
- One (1) 2.95 MMBtu/hr HHV, 422 hp diesel-fired emergency firewater pump engine.
- One (1) 18.77 MMBtu/hr HHV, 2,682 hp diesel-fired emergency generator engine.
- Eight-cell, mechanical draft, evaporative cooling tower controlled by drift eliminators.
- Miscellaneous components in natural gas service, and SF6 containing circuit breakers; controlled by leak detection and repair (LDAR).

26. Upon determination by the permittee that the air contamination sources and air cleaning devices covered by this plan approval are in compliance with all conditions of the plan approval, the permittee shall contact the Department's technical reviewer and schedule the Initial Operating Permit Inspection [25 Pa. Code §127.12b].

27. Upon completion of the Initial Operating Permit Inspection and determination by the Department that the permittee is in compliance with all conditions of the plan approval, the owner or operator shall submit the Title V operating permit application within 120 days after the Department provides notice to the owner or operator that the application is due [25 Pa. Code §127.12b].

28. The permittee shall submit requests to extend the temporary operation periods at least 15 days prior to the expiration date of any authorized period of temporary operation [25 Pa. Code §127.12b].

<u>CT/HRSG (Source ID 101)</u>

<u>RESTRICTIONS</u>

29. Definitions [25 Pa. Code §127.12b]:

  (a) *Startup* is defined as the time from gas turbine ignition to HRSG stack NOx and CO steady state emission compliance.
  (b) *Shutdown* is defined as the time that either HRSG stack NOx or CO emissions exceed steady-state compliance following a normal stop signal to the termination of fuel flow to the gas turbine off. Shutdown shall not exceed 12 minutes per occurrence.
  (c) *Normal operation* is defined as all times except startup, shutdown and malfunction.

(d) *Cold Startup* is defined as a CTG/HRSG unit startup more than 72 hours after shutdown. Cold startup period shall not exceed 55 minutes per occurrence.
(e) *Warm Startup* is defined as a CTG/HRSG unit startup between eight (8) and 72 hours after shutdown. Warm startup periods shall not exceed 40 minutes per occurrence.
(f) *Hot Startup* is defined as a CTG/HRSG unit startup less than eight (8) hours after shutdown. Hot startup shall not exceed 20 minutes per occurrence.

30. Pursuant to the best available technology requirements of 25 Pa. Code 127.1 and 127.12, the total hours of startups and shutdowns for the combined-cycle power block shall not exceed 162.2 hours in any 12-month rolling period.

31. During normal operation, emissions from the combined cycle combustion turbine, Source ID 101, shall not exceed [25 Pa. Code §127.12b]:

(a) Nitrogen Oxides (NOx): 2.0 ppmvd @ 15% O2
NOx: 34.76 lb/hr

Compliance Method/Averaging Period
Initial: U.S. EPA Reference Method 7E
Continuous: 1-hour block

(b) Carbon Monoxide (CO): 2.0 ppmvd @ 15% O2
CO: 21.12 lb/hr

Compliance Method/Averaging Period
Initial: U.S. EPA Reference Method 10
Continuous: 1-hour block

(c) Volatile Organic Compounds (VOC): 1.0 ppmvd @ 15% O2 without duct burners and 2.0 ppmvd @ 15% O2 with duct burners

Compliance Method/Averaging Period
Initial: U.S. EPA Reference Methods 18 and 25A
Continuous: 3-hour block based on initial test and VOC and CO correlation

(d) Total Particulate Matter (PM):
0.0072 lb/MMBtu HHV
PM: 34.19 lb/hr

Compliance Method/Averaging Period
U.S. EPA Reference Methods 201/201A or equivalent and Method 202.
3-hour

(e) Total Particulate Matter with an aerodynamic diameter less than 10 microns (PM10):
0.0072 lb/MMBtu HHV
PM10: 34.19 lb/hr

Compliance Method/Averaging Period

U.S. EPA Reference Methods 201/201Aor equivalent and Method 202
3-hour

(f) Total Particulate Matter with an aerodynamic diameter less than 2.5 microns (PM2.5):
0.0072 lb/MMBtu HHV
PM2.5: 34.19 lb/hr

Compliance Method/Averaging Period
U.S. EPA Reference Methods 201/201Aor equivalent and Method 202
3-hour

(g) Sulfuric Acid Mist (H_2SO_4): 0.0007 lb/MMBtu HHV

Compliance Method/Averaging Period
U.S. EPA Reference Method 8
Annual

(h) Sulfur Dioxide (SO_2): 0.0011 lb/MMBtu HHV

Compliance Method/Averaging Period
U.S. EPA Reference Method 6C
Annual

(i) Formaldehyde (HCHO): 91 ppbvd @ 15% O_2

Compliance Method/Averaging Period
Initial: U.S. EPA Reference Method 320, or ASTM D6348-12
Continuous: 3-hour block based on initial test and HCHO to CO correlation.

(j) Ammonia Slip (NH_3): 5.0 ppmvd @ 15% O_2 on a 3-hour average.

Compliance Method/Averaging Period
Initial: U.S. EPA Conditional Test Method CTM-027
Continuous: 12-month rolling

(k) Greenhouse Gases, expressed as Carbon Dioxide Equivalent (CO_2e): 879 lbs CO_2/MWh (gross).

Compliance Method/Averaging Period
Initial: U.S. EPA Reference Method 3A
Continuous: 12-month rolling

32. At all times, including startup and shutdown, emissions from the combined cycle combustion turbine, Source IDs 101, shall not exceed the following on a 12-month rolling basis [25 Pa. Code §127.12b]:

(a) Nitrogen Oxides (NOx): 169.36 tpy

(b) Carbon Monoxide (CO): 151.41 tpy

(c) Volatile Organic Compounds (VOC): 59.31 tpy

(d) Total Particulate Matter (PM): 105.28 tpy

(e) Total Particulate Matter with an aerodynamic diameter less than 10 microns (PM10): 105.28 tpy

(f) Total Particulate Matter with an aerodynamic diameter less than 2.5 microns (PM2.5): 105.28 tpy

(g) Sulfuric Acid Mist (H2SO4): 13.04 tpy

(h) Sulfur Dioxide (SO2): 23.12 tpy

(i) Formaldehyde (HCHO): 5.77 tpy

(j) Total HAPs: 18.38 tpy

(k) Greenhouse Gases, expressed as Carbon Dioxide Equivalent (CO2e): 2,298,774 tpy

33. The permittee may not permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following [25 Pa. Code §127.12b]:

(a) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any 1 hour.
(b) Equal to or greater than 20% for a period or periods aggregating more than 3 minutes during startup and shutdown.
(c) Equal to or greater than 30% at any time.

34. Average fuel sulfur content shall not exceed 0.4 gr/100 scf natural gas on an annual basis [25 Pa. Code §127.12b].

35. The combined cycle combustion turbine shall be equipped with dry low-NOx burners, selective catalytic reduction, and oxidation catalysts [25 Pa. Code §127.12b].

<u>TESTING REQUIREMENTS</u>

36. Within 180 days after initial startup, or on an alternative schedule as approved by the Department, the permittee shall conduct EPA reference method stack testing for VOC, formaldehyde, PM (filterable and condensable), PM10 (filterable and condensable), PM2.5 (filterable and condensable), sulfuric acid mist, SO2, and carbon dioxide (CO2) in accordance with the requirements of 25 Pa. Code §139 and applicable EPA reference methods [25 Pa. Code §127.12b].

37. The permittee shall conduct subsequent EPA reference method stack testing for VOC, formaldehyde, PM (filterable and condensable), and CO2 no less often than every five years after initial testing. The frequency of such subsequent testing may be altered based on the test results and only with prior written approval from the Department [25 Pa. Code §127.12b].

38. CEMS approval [25 Pa. Code §127.12b]:

(a) Initial Application (Phase I)

A proposal containing information as listed in the Phase I section of the Department's Continuous Source Monitoring Manual for each CEMS must be submitted at least 180 days prior to the initial startup date of the combustion turbine.

(b) Performance Testing (Phase II)

Testing as listed in the Phase II section of the Department's Continuous Source Monitoring Manual must be completed for the CEMS no later than 180 days after initial startup date of the combustion turbine and no later than 60 days after each combustion turbine achieves normal process capacity.

(c) Final Approval (Phase III)

The final report of testing as listed in the Phase III section of the Department's Continuous Source Monitoring Manual must be submitted no later than no later than 60 days after completion of testing. An operating permit will not be issued until each CEMS has received Phase III approval, in writing from the Department. Until Phase III is granted by the Department, operation shall be covered solely by condition of a plan approval.

(d) Each Phase I, Phase II, and Phase III submittal must be provided to the Department through CEMDPS*Online.

(e) Extension of any Phase deadline may be granted only with appropriate justification and written Department approval.

Compliance with any subsequently issued revisions to the Continuous Source Monitoring Manual will constitute compliance with the regulations.

<u>MONITORING REQUIREMENTS</u>

39. Monitoring requirements [25 Pa. Code §123.51]

(a) This section applies to combustion units with a rated heat input of 250 million Btus per hour or greater and with an annual average capacity factor of greater than 30%.

(b) Sources subject to this section shall install, operate and maintain continuous nitrogen oxides monitoring systems and other monitoring systems to convert data to required reporting units in compliance with Chapter 139, Subchapter C (relating to requirements for continuous in-stack monitoring for stationary sources).

(c) Sources subject to this section shall submit results on a regular schedule and in a format acceptable to the Department and in compliance with Chapter 139, Subchapter C.

(d) Continuous nitrogen oxides monitoring systems installed under the requirements of this section shall meet the minimum data availability requirements in Chapter 139, Subchapter C.

(e) The Department may exempt a source from the requirements of subsection (b) if the Department determines that the installation of a continuous emission monitoring system would not provide accurate determination of emissions or that installation of a continuous emission monitoring system cannot be implemented by a source due to physical plant limitations or to extreme economic reasons. A source exempted from the requirements of subsection (b) shall satisfy alternative emission monitoring and reporting requirements proposed by the source and approved by the Department which provide oxides emission data that is representative of actual emissions of the source.

(f) Sources subject to this section shall comply by October 20, 1993, unless the source becomes subject to the requirements later than October 20, 1990. For sources which become subject to the requirements after October 20, 1990, the source has 36 months from the date the source becomes subject to this section. The Department may issue orders providing a reasonable extension of time for sources that have made good faith efforts to install, operate and maintain continuous monitoring devices, but that have been unable to complete the operations within the time period provided.

40. Continuous Emission Monitoring System (CEMS) Requirements [25 Pa. Code §127.12b]:

The following continuous emission monitoring systems (CEMS) must be installed, approved by the Department, operated and maintained in accordance with the requirements of 25 Pa. Code Chapter 139, Subchapter C (relating to requirements for source monitoring for stationary sources), and the "Submittal and Approval", "Record Keeping and Reporting", and "Quality Assurance" requirements of Revision No. 8 of the Department's Continuous Source Monitoring Manual (274-0300-001), and 40 CFR Part 60 Subparts A and KKKK, and 40 CFR Part 75, as applicable.

(a) CEMS #1
(1) Source to be monitored: Source ID 101
(2) Parameter to be reported: NOx
(3) Units of measurement to be reported: ppmvd and lb/hr
(4) Moisture basis of measurement to be reported: Dry
(5) Correction basis of measurements to be reported: 15% O2; correction to 15% O2 is not permitted for the 30-operating day operating hour average per 40 CFR §60.4350(c).
(6) Data substitution required: 40 CFR Part 60 Subpart KKKK, 40 CFR Part 75, and Revision No. 8 of the Department's continuous Source Monitoring Manual (274-0300-001) as applicable.
(7) Emission Standards:

(i) Emission Standard #1
1. Emission Standard Averaging Period Description: 1-hour average, block
2. Emission Standard Value: 2.0 ppmvd (normal) and 34.76 lb/hr (normal)
3. Emission Standard Direction: Violation if greater than emission standard value.
4. Variable Emission Standard: N/A
5. Emission Standard and/or Status: N/A

(b) CEMS #2
(1) Source to be monitored: Source ID 101
(2) Parameter to be reported: CO
(3) Units of measurement to be reported: ppmvd and lb/hr
(4) Moisture basis of measurement to be reported: Dry
(5) Correction basis of measurements to be reported: 15% O2.

(6) Data substitution required: Revision No. 8 of the Department's continuous Source Monitoring Manual (274-0300-001) as applicable.
(7) Emission Standards:

(i) Emission Standard #2
1. Emission Standard Averaging Period Description: 1-hour average, block
2. Emission Standard Value: 2.0 ppmvd (normal) and 21.12 lb/hr (normal)
3. Emission Standard Direction: Violation if greater than emission standard value.
4. Variable Emission Standard: N/A
5. Emission Standard and/or Status: N/A

(c) CEMS #3
(1) Source to be monitored: Source ID 101
(2) Parameter to be reported: NH3
(3) Units of measurement to be reported: ppmvd
(4) Moisture basis of measurement to be reported: Dry
(5) Correction basis of measurements to be reported: 15% O2.
(6) Data substitution required: Revision No. 8 of the Department's continuous Source Monitoring Manual (274-0300-001) as applicable.
(7) Emission Standards:

(i) Emission Standard #3
1. Emission Standard Averaging Period Description: 3-hour average, block
2. Emission Standard Value: 5.0 ppmvd (normal)
3. Emission Standard Direction: Violation if greater than emission standard value.
4. Variable Emission Standard: N/A
5. Emission Standard and/or Status: N/A

* Compliance with any subsequently issued revisions to the Continuous Source Monitoring Manual will constitute compliance with the regulations.

41. CO2 emissions from the combined cycle combustion turbine and associated duct-fired HRSG shall be monitored using the methods in 40 CFR Part 75.13 [25 Pa. Code §127.12b].

<u>RECORDKEEPING REQUIREMENTS</u>

42. The permittee shall maintain the following comprehensive and accurate records [25 Pa. Code §127.12b]:

(a) Monthly heat input and power output on a 12-month rolling basis.
(b) The date time and duration of each startup and shutdown event on a 12-month rolling basis.
(c) Ammonia injection rate.
(d) Duct burner hours of operation on a 12-month rolling basis.
(e) Requirements established in 25 Pa. Code §139 Subchapter C, requirements for source monitoring for stationary sources.
(f) Requirements in the most recent version of the Department's Continuous Source Monitoring Manual.

43. The permittee shall comply with the recordkeeping requirements established in 25 Pa. Code Chapter 139, Subchapter C (relating to requirements for source monitoring for stationary sources), the "Record

Keeping and Reporting" requirements in Revision No. 8 of the Department's Continuous Source Monitoring Manual (274-0300-001), and the recordkeeping requirements established in 40 CFR §§60.7 and 60.13, 40 CFR Part 60 Subpart KKKK, and Part 75 Subpart F, as applicable.

Compliance with any subsequently issued revisions to the Continuous Source Monitoring Manual will constitute compliance with the regulations [25 Pa. Code §127.12b].

REPORTING REQUIREMENTS

44. The permittee shall submit quarterly reports of continuous emission monitoring to the Department in accordance with the requirements established in 25 Pa. Code Chapter 139, Subchapter C (relating to requirements for source monitoring for stationary sources), the "Record Keeping and Reporting" requirements as established in Revision No. 8 of the Department's Continuous Source Monitoring Manual (274-0300-001), and the reporting requirements established 40 CFR §§60.13 and 60.19, 40 CFR Part 60 Subpart KKKK, and Part 75 Subpart G, as applicable [25 Pa. Code §127.12b].

(a) The permittee shall report emissions for all periods of unit operation, including startup, shutdown and malfunction.

(b) Initial quarterly reports following system certification shall be submitted to the Department within 35 days following the date upon which the Department notifies the owner or operator, in writing, of the approval of the continuous source monitoring system for use in determining compliance with applicable emission standards.

(c) Subsequent quarterly reports shall be submitted to the Department within 30 days after the end of each calendar quarter.

(d) Failure to submit required reports of continuous emission monitoring within the time periods specified in this Condition, shall constitute violations of this authorization, unless approved in advance by the Department in writing.

*Compliance with any subsequently issued revisions to the Continuous Source Monitoring Manual will constitute compliance with the regulations.

ADDITIONAL REQUIREMENTS

45. CEMS Data Availability Standards [25 Pa. Code §127.12b].

CEMS #1, CEMS #2, CEMS #3

(a) Data Availability Standard

(1) In accordance with 25 Pa. Code Section 139.101(12), required monitoring shall, at a minimum, meet one of the following data availability requirements unless otherwise stipulated in this permit or an order issued under Section 4 of the Air Pollution Control Act:

(i) In each calendar month, at least 90% of the time periods for which an emission standard or an operational parameter applies, shall be valid as set forth in the Quality Assurance section of Revision No. 8 of the Department's Continuous Source Monitoring Manual (274-0300-001).
(ii) In each calendar quarter, at least 95% of the hours shall be valid as set forth in the Quality Assurance section of Revision No. 8 of the Department's Continuous Source Monitoring Manual (274-0300-001).

(2) For purposes of calculating data availability, ''process down'' time, as specified in Revision No. 8 of the Department's Continuous Source Monitoring Manual (274-0300-001), shall be considered valid time.

(3) Emission Standard(s) to which data availability standard applies:

(i) NOx: ppmvd, lb/hr
(ii) CO: ppmvd, lb/hr

(4) Each 3-hour block average subject to an emissions standard shall be comprised of three 1-hour averages of normal source operation. Emissions occurring during exempt periods of operation (including startup, shutdown, and malfunction) are to be excluded from such 3-hour averages but must be included when calculating 1-year sum tons per year emissions.

Compliance with any subsequently issued revisions to the Continuous Source Monitoring Manual will constitute compliance with the regulations.

46. Within 30 days of the selection of the specific manufacturer and model of the control devices (SCR and oxidation catalyst), the permittee shall submit the specifications to the Department [25 Pa. Code §127.12b].

47. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart KKKK [40 CFR § 60.4300 through § 60.4420].

48. The permittee shall comply with all applicable requirements of 40 CFR Part 60 Subpart TTTT [40 CFR §60.5508 through §60.5580]

Auxiliary Boiler (Source ID 031)

RESTRICTIONS

49. The emissions from the auxiliary boiler shall not exceed the following [25 Pa. Code §127.12b]:

(a) NOx: 0.011 lb/MMBtu.
(b) CO: 0.037 lb/MMBtu.

50. The permittee shall not allow the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following [25 Pa. Code §127.12b]:

(a) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any one hour.
(b) Equal to or greater than 30% at any time.

TESTING REQUIREMENTS

51. Within 180 days after initial startup of the auxiliary boiler, or on an alternative schedule as approved by the Department, the permittee shall conduct EPA reference method stack testing for NOx and CO in accordance with the requirements of 25 Pa. Code §139 [25 Pa. Code §127.12b].

RECORDKEEPING REQUIREMENTS

52. The Owner/Operator shall comply with the applicable fuel usage recordkeeping requirements specified in 40 CFR §60.48c.

53. The Owner/Operator shall comply with the applicable notification requirements specified in 40 CFR §60.48c.

ADDITIONAL REQUIREMENTS

54. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart Dc [40 CFR § 60.40c through § 60.49c].

Fuel Gas Heater (Source ID 032)

RESTRICTIONS

55. The emissions from the dew point heater shall not exceed the following [25 Pa. Code §127.12b]:

(a) NOx: 0.011 lb/MMBtu.
(b) CO: 0.037 lb/MMBtu.

56. The permittee shall not allow the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following [25 Pa. Code §127.12b]:

(a) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any one hour.
(b) Equal to or greater than 30% at any time.

MONITORING REQUIREMENTS

57. Within 180 days after initial startup of the fuel gas heater, or on an alternative schedule as approved by the Department, the permittee shall conduct portable analyzer testing for NOx and CO in accordance with the requirements of 25 Pa. Code §139 and applicable EPA conditional test methods or ASTM D6522-00 [25 Pa. Code §127.12b].

Emergency Diesel Generator (Source ID 102)

RESTRICTIONS

58. The emergency diesel generator shall be a certified Tier II engine [25 Pa. Code §127.12b].

59. Operation of the emergency diesel generator shall not exceed 100 hours on a 12-month rolling basis except for emergency use [25 Pa. Code §127.12b].

60. Sulfur content of the diesel fuel combusted by the emergency diesel generator shall not exceed 15 ppm [25 Pa. Code §127.12b].

61. The cetane index or aromatic content of the diesel fuel shall have:

    (a) A minimum cetane index of 40; or
    (b) A maximum aromatic content of 35 volume percent.

62. The permittee shall not allow the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following [25 Pa. Code §127.12b]:

    (a) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any one hour.
    (b) Equal to or greater than 30% at any time.

RECORDKEEPING REQUIREMENTS

63. The permittee shall maintain records of the fuel certification reports for each delivery of fuel to verify compliance with the fuel restriction requirements [25 Pa. Code §127.12b].

64. The permittee shall maintain records of the hours of operation for maintenance and testing, emergency demand response, and non-emergency use [25 Pa. Code §127.12b].

ADDITIONAL REQUIREMENTS

65. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart IIII [40 CFR § 60.4200 through § 60.4219].

66. The permittee meets the requirements of 40 CFR Part 63, Subpart ZZZZ by meeting the requirements of 40 CFR Part 60, Subpart IIII [25 Pa. Code §127.12b].

Emergency Fire Pump Engine (Source ID 103)

RESTRICTIONS

67. The emergency fire pump engine shall be a certified Tier III engine [25 Pa. Code §127.12b].

68. Operation of the emergency fire pump engine shall not exceed 100 hours on a 12-month rolling basis except for emergency use [25 Pa. Code §127.12b].

69. Sulfur content of the diesel fuel combusted by the fire pump engine shall not exceed 15 ppm [25 Pa. Code §127.12b].

70. The cetane index or aromatic content of the diesel fuel shall have:

    (a) A minimum cetane index of 40; or
    (b) A maximum aromatic content of 35 volume percent.

71. The permittee shall not allow the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following [25 Pa. Code §127.12b]:

(a) Equal to or greater than 10% for a period or periods aggregating more than 3 minutes in any one hour.
(b) Equal to or greater than 30% at any time.

RECORDKEEPING REQUIREMENTS

72. The permittee shall maintain records of the fuel certification reports for each delivery of fuel to verify compliance with the fuel restriction requirements [25 Pa. Code §127.12b].

73. The permittee shall maintain records of the hours of operation for maintenance and testing, emergency demand response, and non-emergency use [25 Pa. Code §127.12b].

ADDITIONAL REQUIREMENTS

74. The permittee shall comply with all applicable requirements of 40 CFR Part 60, Subpart IIII [40 CFR § 60.4200 through § 60.4219].

75. Compliance with 40 CFR Part 60, Subpart IIII assures compliance with 40 CFR Part 63, Subpart ZZZZ [25 Pa. Code §127.12b].

Cooling Tower (Source ID 104)

RESTRICTIONS

76. Total dissolved solids (TDS) of the cooling tower water shall not exceed 4,000 ppm [25 Pa. Code §127.12b].

MONITORING REQUIREMENTS

77. The permittee shall sample, analyze, and record the circulating water TDS content on a monthly basis [25 Pa. Code §127.12b].

78. The permittee shall continuously monitor and record the circulating water and make up water flow rates on a 24-hour average [25 Pa. Code §127.12b].

RECORDKEEPING REQUIREMENTS

79. The permittee shall maintain the following comprehensive and accurate records [25 Pa. Code §127.12b]:

(a) Monthly circulating water TDS content.
(b) Daily circulating water and make up water flow rates.

WORK PRACTICE REQUIREMENTS

80. The permittee shall install and maintain drift eliminators with a manufacturer's guaranteed drift rate of less than 0.0005% of the circulating water flow rate [25 Pa. Code §127.12b].

Circuit Breakers

81. The permittee shall implement a sulfur hexafluoride (SF6) leak detection program to minimize SF6 leaks as follows:

    (a) Circuit breakers are to be state-of-the-art sealed enclosed-pressure circuit breakers equipped with low-pressure alarms that are triggered when less than 10% of the SF6 by weight has escaped.
    (b) When alarms are triggered, the facility shall take corrective action as soon as practicable to repair the circuit breaker units to a like-new state to prevent the emission of SF6 to the maximum extent possible.
    (c) Leaks shall be repaired no later than fifteen (15) calendar days after the leak is detected.

Components in Natural Gas Service

82. The permittee shall implement a methane (CH_4) leak detection and repair program which includes audible, visual, and olfactory (AVO) inspections conducted on a monthly basis on the natural gas piping components. Records of each inspection shall be maintained in a log and, at a minimum, identify the date, time, name and title of the observer, along with any corrective action taken. Leaks shall be repaired as expeditiously as practicable, but no later than fifteen (15) calendar days after the leak is detected unless the owner or operator must purchase parts or the replacement is technically infeasible without process shutdown or would be unsafe to repair during operation of the unit [25 Pa. Code §127.12b].

NSPS Subpart KKKK (Source ID 101)

83. §60.4320 What emission limits must I meet for nitrogen oxides (NOX)?

    (a) You must meet the emission limits for NOx specified in Table 1 to this subpart [15 ppm @ 15% O2 or 54 nanograms per joule (ng/J) of useful output (0.43 lb/MWh)].
    (b) If you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X.

84. §60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

    (a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section. If your turbine is located in Alaska, you do not have to comply with the requirements in paragraph (a) of this section until January 1, 2008.

        (1) You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;
        (2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement; or
        (3) N/A

    (b) N/A

85. §60.4333 What are my general requirements for complying with this subpart?
    (a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

    (b) When an affected unit with heat recovery utilizes a common steam header with one or more combustion turbines, the owner or operator shall either:

        (1) Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common heat recovery unit; or

        (2) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the heat recovery unit for each of the affected combustion turbines. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions related under this part.

86. §60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

    (a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

    (b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

        (1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
        (2) N/A

87. §60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

    (a) Each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

    (b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit

operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

88. §60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

(1) N/A [Not simple-cycle]

(2) For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW.

(3) N/A

(g) N/A

(h) For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

89. §60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?

You must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

90. §60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?

You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

91. §60.4375 What reports must I submit?

(a) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

(b) For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

NSPS Subpart IIII (Source IDs 102 and 103)

92. §60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) and other persons as specified in paragraphs (a)(1) through (4) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) N/A

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are:

(i) Manufactured after April 1, 2006, and are not fire pump engines, or
(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(b) N/A

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) N/A

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

93. §60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) N/A

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) N/A

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) N/A

94. §60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

95. §60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) N/A

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) N/A

(e) N/A

96. §60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) N/A

(c) N/A

(d) N/A

(e) N/A

(f) N/A

(g) N/A

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

97. §60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine that does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter prior to startup of the engine.

(b) N/A

98. §60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) N/A

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that

applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of this section.

(d) N/A

(e) N/A

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii)Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100

hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) N/A

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent

practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

99. §60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the equation in §60.4212(c).

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) N/A

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

100. §60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) N/A

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) N/A

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii)Engine site rating and model year.

(iv)Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vi)Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

101. §60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

NSPS Subpart TTTT (Source ID 101)

102. §60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section. The GHG standards included in this subpart also apply to any steam generating unit or IGCC that commenced modification after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (2) of this section.

(1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel); and

(2) Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system.

(b) N/A

103. §60.5515 Which pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases. The greenhouse gas standard in this subpart is in the form of a limitation on emission of carbon dioxide.

(b) PSD and title V thresholds for greenhouse gases. (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §51.166(b)(48) of this chapter and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in §52.21(b)(49) of this chapter.

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

104. §60.5520 What CO2 emission standard must I meet?

The permittee shall comply with the applicable emission standards specified in 40 CFR §60.5520.

105. §60.5525 What are my general requirements for complying with this subpart?

The permittee shall comply with the applicable general requirements specified in 40 CFR §60.5525.

106. §60.5535 How do I monitor and collect data to demonstrate compliance?

The permittee shall comply with the applicable monitoring requirements specified in 40 CFR §60.5535.

107. §60.5550 What notifications must I submit and when?

The permittee shall comply with the applicable notification requirements specified in 40 CFR §60.5550.

108. §60.5555 What reports must I submit and when?

The permittee shall comply with the applicable reporting requirements specified in 40 CFR §60.5555.

109. §60.5560 What records must I maintain?

The permittee shall comply with the applicable recordkeeping requirements specified in 40 CFR §60.5560.

110. §60.5570 What parts of the general provisions apply to my affected EGU?

The permittee shall comply with the applicable general provisions specified in 40 CFR §60.5560.