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August 31, 2016
mk033-16

Mr. Bachir Bouzid
Section Chief, Operating Permits
Air Quality Permitting Program
New Jersey Department of Environmental Protection
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**Subject: CPV Keasbey, LLC
Township of Woodbridge, Middlesex County, New Jersey
Facility ID: 18940
Submittal of Air Permit Application for a Nominal 630 MW
Combined Cycle Power Facility**

Dear Mr. Bouzid:

TRC Environmental Corporation (TRC) is providing a copy of this Subchapter 22.24 air permit application and technical support documentation on behalf of CPV Keasbey, LLC (CPV Keasbey) to construct a nominal 630-megawatt combined cycle electric generating facility (to be known as the Keasbey Energy Center) on a parcel of land controlled by CPV Shore Urban Renewal, LLC in the Township of Woodbridge, Middlesex County, New Jersey. This parcel of land borders the existing CPV Shore, LLC Woodbridge Energy Center. This application was submitted via NJDEP online on August 31, 2016.

The Keasbey Energy Center will represent a significant modification of the Woodbridge Energy Center. Since the Keasbey Energy Center, as a major modification, will potentially emit more than the Significant Emission Rates (SERs) of several air pollutants, it is subject to Prevention of Significant Deterioration (PSD) permitting.

The enclosed air permit application support document, which includes a print of the RADIUS application in Appendix A, describes the emissions processes and equipment at the facility, details the emissions calculations, and addresses applicable regulatory requirements for the proposed Project. Once air quality dispersion modeling for the project has been completed, both the Air Quality Impact Analysis and Environmental Justice will be submitted to the Department under separate cover as Sections 5 and 6, respectively, of the technical support document.

The Keasbey Energy Center will consist of one (1) General Electric (GE) 7HA.02 combustion turbine generator with a heat recovery steam generator (HRSG) equipped with a natural gas fired duct burner that will be tied into one (1) steam turbine generator.

The proposed facility will be fueled primarily by natural gas but will be capable of utilizing ultra-low sulfur diesel (ULSD). Engineering design plans also reflect the use of a wet mechanical draft cooling tower with additional supporting ancillary equipment including a natural gas fired auxiliary boiler, an emergency diesel generator, an emergency diesel fire pump, a one (1) million gallon ULSD storage tank, and one (1) 20,000 gallon aqueous ammonia storage tank. The combined cycle combustion turbine will be designed to operate on a continuous basis but will not operate at steady-state below 30% load on natural gas and 50% load on ULSD.

Please feel free to contact me at 201-508-6954 or Ted Main at 201-508-6960 should you have any questions regarding this application. We look forward to the opportunity to work with you on this project.

Sincerely,

TRC



Michael D. Keller
Principal – Power Generation and Air Quality

Attachment

cc: G. John, NJDEP (CD-ROM attachment)
S. Riva, U.S. EPA Region II (with attachment)
J. Webster, U.S. FWS (CD-ROM attachment)
S. Johnson, National Park Service (CD-ROM attachment)
J. Donovan, CPV (CD-ROM attachment)
A. Urquhart, CPV (with attachment)
T. Main, TRC (without attachment)
TRC Project File 252973

mk033-16.ltr.doc

**Keasbey Energy Center
Combined Cycle Power Facility
PSD Air Permit Application**

Prepared for:

CPV Keasbey, LLC

Prepared by:

TRC Environmental Corporation
1200 Wall Street West, 5th Floor
Lyndhurst, NJ 07071

August 2016

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LIST OF ACRONYMS

Acronym	Definition
AAR	Authorized Account Representative
AGL	above grade level
AP-42	Compilation of Air Pollutant Emission Factors, Fifth Edition
AQRV	Air Quality Related Values
BACT	Best Available Control Technology
BHP	Brake Horsepower
BPIPPRM	Building Profile Input Program for PRIME (version 04274)
Btu	British thermal unit
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CHP	combined heat and power, or cogeneration
CO	carbon monoxide
CO ₂	carbon dioxide
CTG	combustion turbine generator
DB	duct burner
DEM	Digital Elevation Model
DLN	dry low-NO _x
EJ	Environmental Justice
ERCs	emission reduction credits
F	Fluoride
°F	Degrees in Fahrenheit
FGD	Flue Gas Desulfurization
FGR	flue gas recirculation
FLM	Federal Land Manager
ft	Feet
FTE	Full Time Equivalent (employee)
GE	General Electric
GEP	good engineering practice
GPM	gallons per minute
GHG	greenhouse gas
H ₂ O	Water
H ₂ SO ₄	sulfuric acid
HAP	Hazardous Air Pollutant
HF	Hydrogen Fluoride

Acronym	Definition
HHV	higher heating value
HRSG	heat recovery steam generator
°K	degrees on the Kelvin scale
Km	kilometer
LAER	Lowest Achievable Emission Rate
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
LNB	low-NO _x burner
µg/m ³	microgram per cubic meter
m/s	meters per second
MACT	Maximum Achievable Control Technology
KEC	Keasbey Energy Center
MCUA	Middlesex County Utilities Authority
MMBtu/hr	million British thermal units per hour
MSL	mean sea level
MW	megawatt
N ₂	nitrogen
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum 1983
NCDC	National Climatic Data Center
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH ₃	ammonia
(NH ₄) ₂ SO ₄	ammonium sulfate
NH ₄ HSO ₄	ammonium bisulfate
NJAC	New Jersey Administrative Code
NJDEP	New Jersey Department of Environmental Protection
NO	nitric oxide
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
NNSR	Non-Attainment New Source Review
NSR	New Source Review
NWA	National Wilderness Area
NWR	National Wildlife Refuge
NWS	National Weather Service
O ₂	Oxygen
O ₃	Ozone
OTC	Ozone Transport Commission

Acronym	Definition
OTR	Ozone Transport Region
Pb	Lead
PM	particulate matter
PM-2.5	Particulate matter with an aerodynamic diameter of 2.5 microns or less
PM-10	particulate matter with an aerodynamic diameter of 10 microns or less
ppm	parts per million
ppmvd	parts per million dry volume
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RGGI	Regional Greenhouse Gas Initiative
scf	standard cubic feet
SCR	Selective Catalytic Reduction
SER	Significant Emission Rate
SICs	Significant Impact Concentrations
SILs	Significant Impact Levels
SIP	State Implementation Plan
SMC	Significant Monitoring Concentration
SNCR	selective noncatalytic reduction
SOTA	State of the Art
SO ₂	sulfur dioxide
SO ₃	sulfur trioxide
SOTA	State of the Art
STG	steam turbine generator
TDS	Total Dissolved Solids
tpy	tons per year
TRI	Toxic Release Inventory
TSP	total suspended particulate
TSS	Total Suspended Solids
ULSD	Ultra-low sulfur diesel
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

1.0 INTRODUCTION

1.1 Project Overview

CPV Power Holdings, LP (CPV) is a leading North American electric power generation development and asset management company headquartered in Silver Spring, Maryland with offices in Braintree, Massachusetts and San Francisco, California. CPV Keasbey, LLC (CPV Keasbey), a wholly owned business entity of CPV, is proposing to construct a nominal 630-megawatt (MW) dual fuel (natural gas and ultra-low sulfur diesel – ULSD) fired 1-on-1 combined cycle electric power facility, to be known as the Keasbey Energy Center (the Project), on land directly adjacent to the existing 725 MW Woodbridge Energy Center.

The proposed Project will be constructed on an approximately eleven (11) acre parcel of land (the “Property”) located at 1070 Riverside Drive Township of Woodbridge, Middlesex County, New Jersey (Block 93, Lot 100.02 on the official Woodbridge Township Tax Maps). The Property is located within the Keasbey Brownfield Redevelopment Area on a former chemical plant site that has undergone clean-up and remediation pursuant to the NJDEP’s Site Remediation Program. The Property and will be sub-divided from the approximately 27.5 acre parcel of land controlled by CPV Shore Urban Renewal, LLC and share a property boundary with CPV Shore, LLC’s (CPV Shore) Woodbridge Energy Center. Figures 1-1 and 1-2, respectively, show the proposed Project location and the surrounding area.

The Project air contaminant emissions sources will include a single dual-fuel fired combustion turbine with a natural gas supplementary-fired heat recovery steam generator (HRSG); a natural gas-fired auxiliary boiler and; an emergency diesel generator and emergency diesel fire pump. Combined cycle power will be generated from a steam turbine generator serviced by a wet evaporative cooling tower. The Project will be permitted as a major modification to an existing major source, CPV Shore’s Woodbridge Energy Center (PID # 18940 Woodbridge Energy Center) due to CPV’s common control of both facilities. CPV’s common control of both facilities arises from CPV’s majority ownership in both CPV Keasbey and CPV Shore, where CPV controls 100% ownership interest in CPV Keasbey and 57.5% ownership interest in CPV Shore. For this reason CPV is considered to have common control of both facilities.

The proposed Project is located in an attainment area for sulfur dioxide (SO₂), nitrogen dioxide (NO₂), carbon monoxide (CO), particulate matter with an aerodynamic diameter less than 10 micrometers (um) (PM-10), and particulate matter with an aerodynamic diameter less than 2.5 um (PM-2.5). Since the Project will potentially emit in excess of the Significant Emission Rates (per year of several air pollutants), it will be subject to Prevention of Significant Deterioration (PSD) permitting (see Table 1-1). Emissions of nitrogen oxides (NO_x), ozone (as VOC), sulfuric acid (H₂SO₄), PM-10, PM-2.5, and CO will exceed the pollutant specific PSD significant emission

rates (SER) and, consequently, a Best Available Control Technology (BACT) analysis and an air dispersion modeling analysis is required for these pollutants.

Middlesex County is designated as moderate non-attainment for the 8-hour ozone standard. Since potential annual emissions of NO_x and VOC, both ozone precursors, exceed the major source thresholds (i.e., 25 tons per year of NO_x and/or 25 tons per year of VOC), the proposed facility is subject to non-attainment New Source Review (NSR) for these two ozone precursors.

An air quality impact analysis will be required to demonstrate that the proposed facility will be compliant with all applicable PSD increment levels, National Ambient Air Quality Standards (NAAQS), and New Jersey Ambient Air Quality Standards (NJAAQS). Initially, the air quality impact of the proposed facility will be modeled using potential emission rates to determine if the facility will yield significant air quality impacts (i.e., maximum modeled concentrations greater than the PSD significant impact concentrations). The significance modeling will be performed for multiple operating loads and multiple ambient temperatures. The pollutant-specific “worst-case” operating scenario determined from the significance modeling analysis will be used in all subsequent modeling, including any PSD increment and multiple source NAAQS/NJAAQS analyses, if necessary.

The proposed Keasbey Energy Center will consist of one (1) General Electric (GE) 7HA.02 combustion turbine generator (CTG) that will utilize natural gas as its primary fuel source. Ultra-low sulfur diesel (ULSD) will be utilized as a back-up fuel for up to 720 hours per year. A heat recovery steam generator (HRSG) downstream of the combustion turbine will recover heat from the exhaust gases to generate steam. It will be equipped with a natural gas fired duct burner for supplementary firing. The HRSG will tie-in to a single steam turbine generator (STG). Electricity generated by the Project will be sold to the regional Pennsylvania-New Jersey-Maryland (PJM) electric power grid. Supporting ancillary equipment includes a natural gas fired auxiliary boiler, a wet mechanical draft cooling tower, an emergency diesel generator and supporting day tank, an emergency diesel fire pump and supporting day tank, and one (1) 20,000 gallon aqueous ammonia tank. Both the emergency diesel generator and the diesel fire pump will be fueled by ULSD.

The combustion turbine will utilize a dry low-NO_x (DLN) combustor (during natural gas firing), water injection (during ULSD firing), and selective catalytic reduction (SCR) system to control NO_x emissions. An oxidation catalyst will be located in the HRSG upstream of the SCR and used to control emissions of carbon monoxide (CO) as well as volatile organic compounds (VOC). Exhaust gases from the combined cycle unit (after emission controls) will be directed to an individual stack at 160 feet above grade with an inner exit flue diameter of 22 feet. In addition, CTG inlet air will be cooled using an evaporative cooler and/or wet compression when ambient

temperatures are high, in order to cool the compressor inlet air which will improve CTG efficiency and increase CTG generation output.

The Project will operate up to the equivalent of 8,760 full-load hours per year, but may operate at partial loads. Part-load turbine operation will be limited to the range between 30 to 100% of turbine load on natural gas firing and between 50 to 100% of turbine load on ULSD firing.

1.2 Summary of Federal and State-Level Emission Control Requirements

The following provides a general description of the proposed facility's regulatory and emission control requirements set forth by applicable Federal and State-Level air programs. Please see Section 3 of this Air Permit application for a detailed regulatory analysis and Table 3-3 for a comparison of the proposed facility's potential emissions to the regulatory applicability thresholds.

1.2.1 Lowest Achievable Emission Rate

Because the proposed facility is located in a moderate ozone non-attainment area (8-hour standard) and potential emissions of NO_x and VOC, both ozone precursors, exceed 25 tons per year, non-attainment New Source Review (NSR) is required for emissions of NO_x and VOC. A component of NSR is a requirement to meet Lowest Achievable Emission Rate (LAER) limits. To meet the LAER requirement for NO_x emissions, the facility will employ dry low-NO_x burner combustion technology (during natural gas firing), water injection (during ULSD firing), and SCR control technology to control flue gas NO_x emissions from the combustion turbine. For VOC emissions, the facility will employ good combustion practices and an oxidation catalyst as LAER technology for the combined cycle unit. Proposed NO_x and VOC LAER emission limits and control technologies for all combustion units are described in Section 4.

1.2.2 Best Available Control Technology

Best Available Control Technology (BACT) must be applied to control emissions of pollutants that are subject to Prevention of Significant Deterioration (PSD) review based on potential emissions of each pollutant for which the project site area is in attainment. For the proposed combined cycle power facility, BACT is required for CO, sulfuric acid mist (H₂SO₄), PM/PM-10/PM-2.5, and greenhouse gases (GHG). BACT is also triggered for NO_x. Because NO_x is subject to the more stringent LAER requirements discussed above, the LAER requirements for NO_x will also satisfy BACT requirements for NO_x. The Project will meet BACT requirements for CO, H₂SO₄ and PM/PM-10/PM-2.5 emissions by using an oxidation catalyst to control CO emissions and low sulfur fuels for control of H₂SO₄ and PM/PM-10/PM-2.5 emissions. The Project will comply with BACT for GHGs by firing natural gas and ULSD and through energy

efficiency measures. Section 4 presents detailed BACT proposals for the combined cycle unit, in addition to BACT for applicable pollutants from the auxiliary boiler, the wet mechanical draft cooling tower, the emergency diesel generator, and the emergency diesel fire pump.

1.2.3 State Of The Art Technology

Based upon the requirements of N.J.A.C. 7:27-8.12, emissions from new or modified emission units in New Jersey with uncontrolled emissions greater than 5 tons/year are required to incorporate State of the Art (SOTA) performance levels. Based on the SOTA emission thresholds, only the combustion turbine and the auxiliary boiler are subject to SOTA requirements. Compliance with LAER or BACT, or NSPS requirements promulgated on or after August 2, 1995 or performance levels present in a NJDEP SOTA manual(s), constitute compliance with SOTA requirements. Based upon this methodology, the only pollutants not subject to LAER, BACT, or NSPS for which SOTA performance levels are presented are ammonia slip (NH_3) and opacity from the combustion turbine. Keasbey Energy Center is proposing to meet the SOTA guideline performance level of 5 ppmvd @ 15% O_2 for ammonia slip and an opacity standard of 10% for normal steady-state operation.

1.3 Assessment of Air Quality Impact

1.3.1 Facility Location

Topography in the immediate area is generally flat, with elevations at sea level on the Raritan River and elevation rising upwards of and exceeding 200 feet in Fords, New Jersey. Typical terrain elevations on the Project site are approximately 21 feet above mean sea level (MSL).

Existing land uses in the vicinity of the proposed site include industrial development, commercial development, neighborhood businesses, and residential neighborhoods (See Figure 1-2). The nearest residential locations are approximately 0.8 miles (1.3 kilometers) to the northeast, along Sunnyview Oval immediately north of Route 440 and along Georges Post Road immediately south of Route 440.

The proposed facility exhaust stack will be located at approximately 40° 30' 53" North Latitude, 74° 19' 16" West Longitude, North American Datum 1983 (NAD83). The approximate Universal Transverse Mercator (UTM) coordinates of the proposed facility stack are 557,515 meters Easting, 4,485,100 meters Northing, in Zone 18, NAD83. The other emission sources are located in close proximity to the facility combustion turbine/HRSG exhaust stack on the proposed facility property.

1.3.2 Impact on Ambient Air Quality Standards and Class II PSD Increments within the Community

Atmospheric dispersion modeling (to be provided) was performed in accordance with United States Environmental Protection Agency (U.S. EPA) and New Jersey Department of Environmental Protection (NJDEP) modeling guidelines to estimate maximum expected air quality impacts from the proposed facility. The results of this modeling analysis will be reflected in Section 5 (to be provided), which demonstrate that both the National and NJ Ambient Air Quality Standards as well as the PSD Class II increments will be achieved by a comfortable margin within the host community for the Project.

1.3.3 Class I Area Impacts

Proposed major sources within 300 km of a Class I area may be required to perform an assessment of potential impacts in that Class I area. The only Class I area within 300 km of the proposed facility is the Brigantine Wilderness area located in the Edwin B. Forsythe National Wildlife Refuge in New Jersey. This area is located approximately 108 km south of the proposed facility.

On July 12, 2016, TRC submitted a request to the Federal Land Manager (FLM) of this Class I area for a determination as to the need for Class I area air quality and AQRV analyses for the Brigantine Wilderness. On July 13, 2016 the FLM notified TRC that an impact assessment at this Class I area will not be required for this Project (See Appendix D for copies of the relevant correspondence).

1.3.4 Impacts to Soils, Vegetation, Visibility, and Industrial, Commercial, and Residential Growth

An analysis was performed to assess the proposed facility's impact on soils, vegetation, visibility, and industrial, commercial, and residential growth. This analysis (to be provided in Section 5) demonstrated that the proposed facility would have negligible effects on these special concerns.

1.4 Conclusions

The conclusions reached from the results of the engineering and air quality modeling analyses are that the proposed combined cycle facility will: 1) meet all control technology requirements resulting from LAER, BACT, and SOTA; 2) not cause or contribute to a violation of the NAAQS for any pollutant; 3) not exceed the PSD Class II increment for any pollutant; 4) not cause adverse impacts to soils, vegetation, growth and visibility; and 5) comply with all other applicable Federal and New Jersey air quality requirements (to be provided in Section 5).

1.5 Summary of Proposed Emission Limits

Tables 1-2, 1-3, and 1-4, respectively, present a summary of the anticipated permit limits proposed for the Keasbey Energy Center that is located in Woodbridge Township, Middlesex County, New Jersey. These limits reflect the application of LAER, BACT or SOTA control technology, as appropriate. In addition, Section 5 (to be provided) of this application provides atmospheric dispersion modeling documentation that confirms that the facility operating at the proposed limits will not contravene the NAAQS/NJAAQS or PSD Class II increment air quality levels.

1.6 Contents of Application Support Document and Appendices

The application forms for the project have been prepared using NJDEP's RADIUS software. Hard copies of the preconstruction permit application forms are included as Appendix A of this document. Emission calculation spreadsheets providing supporting calculations for the application forms are included as Appendix B. Appendix C presents the results of the RBLC search while Appendix D includes agency correspondence. The air quality modeling protocol is included in Appendix E and the Compliance Certification Statement is included in Appendix F.

1.7 Project Schedule

Preliminary schedule milestones for the planned Keasbey Energy Center combined cycle project are as follows:

- | | |
|---|-----------------------------|
| • Air permit application submitted to NJDEP | August 2016 |
| • Review Period | August 2016 – February 2017 |
| • Public Comment Period | February 2017 |
| • Final Permit Issuance | April/May 2017 |
| • Construction Period | 30 Months (anticipated) |
| • Commercial Operation | May, 2020 |

Table 1-1: Comparison of Facility Potential Emissions to PSD Significant Emission Rates and Non-attainment NSR Thresholds^(a)

Pollutant	Proposed Facility Potential Emissions (tons/yr)	PSD Significant Emissions Increase Level (tons per year)	NNSR Major Source/Modification Threshold (tons per year)
Carbon Monoxide	110.3	100	NA
Sulfur Dioxide	39.9	40	NA
Particulate Matter (PM)	77.6	25	NA
Particulate Matter less than 10 microns (PM-10)	123.6	15	NA
Particulate Matter less than 2.5 microns (PM-2.5)	119.3	10	NA
Nitrogen Oxides	148.7	40	25 ^(b)
Ozone (VOC)	49.9	40	25 ^(b)
Greenhouse Gases (GHG)	2,374,633	75,000 ^(c)	NA
Lead	0.03	0.6	NA
Fluorides	NA	3	NA
Sulfuric Acid Mist	25.1	7	NA
Hydrogen Sulfide	NA	10	NA
Total Reduced Sulfur (including H ₂ S)	NA	10	NA
Reduced Sulfur Compounds (including H ₂ S)	NA	10	NA

Notes:

^(a) Pursuant to 40 CFR 52.21 (b)(23)(i).

^(b) Per N.J.A.C 7:27-18.

^(c) For a major modification to an existing major source.

Table 1-2: Summary of Proposed Permit Limits for the Combustion Turbine and Duct Burner (Natural Gas Fired Steady-State Operation)

Pollutant	Stack Emissions ^{a,b,c}	
	Gas Firing	
	(lb/MMBtu)	(ppm)
Nitrogen Oxides		
CT Only	0.0073	2.0
CT with Duct Burner	0.0074	2.0
Volatile Organic Compounds		
CT Only	0.0013	1.0
CT with Duct Burner	0.0026	2.0
Carbon Monoxide		
CT Only	0.0044	2.0
CT with Duct Burner	0.0045	2.0
PM/PM-10/PM-2.5^d		
CT Only	0.0068	N/A
CT with Duct Burner	0.0070	N/A
Sulfur Dioxide		
CT Only	0.0021	N/A
CT with Duct Burner	0.0021	N/A
Sulfuric Acid Mist		
CT Only	0.0014	N/A
CT with Duct Burner	0.0014	N/A
Ammonia		
CT Only	N/A	5.0
CT with Duct Burner	N/A	5.0

(a) “ppm” refers to ppmvd @ 15% O₂; lb/MMBtu limits are HHV basis. All ppm values are one-hour averages, with the exception of NO_x (3-hour average).

(b) Facility may exceed short-term limits during defined startup and shutdown periods.

(c) All proposed emission limits (in units of ppm, lb/hr, and lb/MMBtu) do not serve as the basis for determining annual emission limits. Refer to Appendix B for potential annual emissions calculations.

(d) Includes filterables, condensables, and sulfates.

Table 1-3: Summary of Proposed Permit Limits for the Combustion Turbine (ULSD Fired Steady-State Operation)

Pollutant	Stack Emissions ^{a,b,c}	
	ULSD Firing	
	(lb/MMBtu)	(ppm)
Nitrogen Oxides		
CT Only	0.0155	4.0
Volatile Organic Compounds		
CT Only	0.0027	2.0
Carbon Monoxide		
CT Only	0.0047	2.0
PM/PM-10/PM-2.5^d		
CT Only	0.0338	N/A
Sulfur Dioxide		
CT Only	0.0018	N/A
Sulfuric Acid Mist		
CT Only	0.0012	N/A
Ammonia		
CT Only	N/A	5.0

(a) “ppm” refers to ppmvd @ 15% O₂; lb/MMBtu limits are HHV basis. All ppm values are one-hour averages, with the exception of NO_x (3-hour average).

(b) Facility may exceed short-term limits during defined startup and shutdown periods.

(c) All proposed emission limits (in units of ppm, lb/hr, and lb/MMBtu) do not serve as the basis for determining annual emission limits. Refer to Appendix B for potential annual emissions calculations.

(d) Includes filterables, condensables, and sulfates.

Table 1-4: Summary of Proposed Permit Limits - Auxiliary Equipment

Pollutant	Emissions			
	Auxiliary Boiler	Emergency Diesel Generator	Emergency Diesel Fire Pump	Cooling Tower
	(lb/MMBtu)	(g/bhp-hr)	(g/bhp-hr)	(lb/hr)
NO _x	0.01	4.63	2.69	N/A
VOC	0.005	0.15	0.31	N/A
CO	0.037	2.61	1.42	N/A
PM/PM-10/PM-2.5	0.007	0.15	0.118	2.39/1.55/0.58
SO ₂	0.006	0.01	0.005	N/A
H ₂ SO ₄	0.00046	0.0008	0.0004	N/A

Note: Sum of NO_x + NMHC (VOC) = 4.78 g/bhp-hr per NSPS IIII for EDG.
Sum of NO_x + NMHC (VOC) = 3.00 g/bhp-hr per NSPS IIII for EDFP.

2.0 PROJECT DESCRIPTION

2.1 Facility Conceptual Design

CPV Keasbey is proposing to construct the Keasbey Energy Center (the Project) which will be a 630 MW (nominal) combined cycle electric power generating facility in Woodbridge Township, Middlesex County, New Jersey. The project will include one (1) General Electric (GE) 7HA.02 combustion turbine that will primarily utilize natural gas but will be capable of utilizing ULSD for up to 720 hours per year. A heat recovery steam generator (HRSG) downstream of the combustion turbine will recover heat from the exhaust gases to generate steam. The HRSG will be equipped with a natural gas fired duct burner and tie-in to a single steam turbine generator (STG). Electricity generated in the CTG and STG will be sold to the regional (PJM) electric power grid. By using the waste heat from the combustion turbine to produce steam and generate additional electricity, the Project will operate with a higher thermal efficiency than many other electricity generating facilities operating within New Jersey and adjacent states. The CTG will be equipped with inlet air cooling systems to further boost power and efficiency on hot days. Supporting ancillary equipment will include a natural gas fired auxiliary boiler, a wet mechanical draft cooling tower, an emergency diesel generator, an emergency diesel fire pump, and an aqueous ammonia tank. Figure 2-1 presents the Keasbey Energy Center general arrangement site plan and Figure 2-2 presents a simplified process flow diagram for the combined cycle unit.

Emissions from the combined cycle unit will be controlled by the use of dry low-NO_x burner technology (for gas firing), water injection (for ULSD firing), and SCR for NO_x, oxidation catalyst for CO and VOC, and the use of clean low-sulfur fuels to minimize emissions of SO₂, PM/PM-10/PM-2.5, and H₂SO₄. Exhaust gases from the combined cycle unit after emission controls will be dispersed to the atmosphere via one (1) 160-foot (above grade) stack. Steam from the steam turbine will be sent to a condenser where it will be cooled to a liquid state and returned to the HRSG. Waste heat from the condenser will be dissipated through the wet mechanical draft cooling tower.

2.2 Natural Gas and ULSD Fired Combined Cycle Unit

CPV Keasbey is proposing to install one (1) combined cycle General Electric (GE) 7HA.02 combustion turbine that will utilize natural gas as the primary fuel and ULSD as a back-up fuel. The maximum combustion turbine heat input capacity at -8 degrees Fahrenheit (°F) ambient temperature firing natural gas is 3,512 million British thermal units per hour (MMBtu/hr) based on the Higher Heating Value (HHV). The maximum combustion turbine heat input capacity at -8 degrees Fahrenheit (°F) ambient temperature firing ULSD is 3,626 million British thermal

units per hour (MMBtu/hr) based on the HHV. The maximum duct burner heat input capacity firing natural gas is 950 million British thermal units per hour (MMBtu/hr) based on the HHV. The exhaust gases leaving the HRSG will be directed to one (1) 160-foot above grade stack.

2.2.1 Control Equipment for the Combined Cycle Unit

The emission control technologies proposed for the combustion turbine exhaust gases include dry low-NO_x (DLN) combustors located within the combustion turbine and water injection and an SCR system located with the heat recovery steam generator to control NO_x emissions. An oxidation catalyst and efficient combustion controls will be used to control emissions of CO and VOC. Emissions of SO₂, PM/PM-10/PM-2.5, and H₂SO₄ will be minimized through the use of low sulfur fuel, as well as efficient combustion controls.

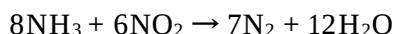
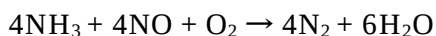
2.2.1.1 DLN Combustor

Dry low-NO_x combustion will control NO_x emissions from the combustion turbine. DLN combustion limits NO_x formation by controlling the combustion process through air/fuel optimization.

2.2.1.2 Selective Catalytic Reduction

The formation of NO_x is determined by the interaction of chemical and physical processes occurring during combustion. There are two principal forms of NO_x - "thermal" NO_x and "fuel" NO_x. Thermal NO_x formation is the result of oxidation of atmospheric nitrogen in the combustion zone. The major factors influencing thermal NO_x formation are temperature, concentrations of nitrogen and oxygen in the inlet air and residence time within the combustion zone. NO_x is formed by the oxidation of fuel-bound nitrogen. NO_x formation can be controlled by adjusting the combustion process and/or installing post-combustion controls.

Selective Catalytic Reduction (SCR) is a supplemental NO_x control technology that is placed in the flue gas stream within the HRSG and downstream of the natural gas-fired duct burner. SCR involves the injection of ammonia (NH₃) into the exhaust gas stream upstream of a catalyst bed. On the catalyst surface, NH₃ reacts with NO_x contained within the flue gas stream to form nitrogen gas (N₂) and water (H₂O) in accordance with the following chemical equations:



The catalyst's active surface includes a metal (e.g., titanium, vanadium, or equivalent) to promote the NO_x reduction process. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path in order to achieve maximum conversion efficiency of NO_x to N₂.

Aqueous ammonia (19.5% by weight) is drawn from a storage tank, vaporized, and injected into the flue gas stream ahead of the catalyst bed. Excess ammonia which is not reacted in the SCR and which is emitted from the stack is referred to as ammonia slip.

2.2.1.3 Oxidation Catalyst

After combustion control, the only practical method to reduce CO emissions from the combined cycle unit is an oxidation catalyst. Exhaust gases from the combustion turbine are passed over a catalyst bed where excess air oxidizes the CO to carbon dioxide. The oxidation catalyst will also reduce VOC emissions. The oxidation catalyst will be located in an optimum temperature region within the HRSG immediately upstream of the SCR ammonia injection grid.

2.2.1.4 Process Controls

The Project will incorporate modern data acquisition and control systems, which will optimize combustion performance. These same systems will minimize pollutant emissions through a combination of operator and software-driven process adjustments and notifications.

2.3 Auxiliary Boiler

The Facility is proposing to install and operate one (1) auxiliary boiler to support start-up and shutdown activities for the combined cycle units. The auxiliary boiler will have a maximum heat input of up to 72.3 MMBtu/hr (HHV) and will combust natural gas only. The total estimated maximum operation is estimated to be 4,000 hours per year. The proposed package boiler will be equipped with an ultra-low NO_x burner and flue gas recirculation (FGR) to control NO_x emissions. Natural gas combustion will minimize the formation of PM/PM-10/PM-2.5 and SO₂. Good combustion practices and design will minimize CO and VOC emissions.

2.4 Emergency Diesel Engines

The proposed facility will include two auxiliary diesel internal combustion (IC) engines: the emergency generator and emergency diesel fire pump. Both of these emergency diesel engines will undergo periodic testing. Testing and operation will not exceed 100 hours per year per engine.

2.5 Cooling Tower

Steam leaving the steam turbine will be condensed in a non-contact condenser. The circulating water through the condenser will be cooled by an evaporative cooling tower. The proposed tower is a wet mechanical-draft design. Each cell has its own fan. The cooling tower will be equipped with a high efficiency drift eliminator (0.0005% efficiency) to minimize water drift losses and associated PM/PM-10/PM-2.5 emissions.

2.6 ULSD and Ammonia Storage Tanks

The Keasbey Energy Center will store ULSD in one (1) 1,000,000 gallon tank, in order to provide a backup fuel supply for the Project, as well as vendor supplied tanks for the emergency diesel and emergency diesel fire pump, respectively. The tanks will be equipped with modern vapor recovery systems. VOC emissions from the tanks are calculated and included in the facility's potential emissions.

Ammonia used in the SCR system of the combined cycle unit will be supplied from one (1) 20,000 gallon aqueous ammonia storage tank. The aqueous ammonia concentration will be limited to no greater than 19.5% by weight. The percentage concentration is below the 40 CFR Part 68, Section 112(r) (Table 1) risk management planning applicability threshold. The aqueous ammonia storage tank will be a closed loop system. As a result, the tank will have no air emissions.

2.7 Other Exempt and Trivial Auxiliary Equipment

In addition to the significant emission sources (combined cycle combustion turbine, auxiliary boiler, etc.), the proposed combined cycle power facility will also contain various exempt and trivial auxiliary equipment and activities, which will not require an air permit. Exempt and trivial auxiliary equipment either have zero emissions or are specifically listed as exempt or trivial in accordance with NJDEP air quality regulations.

2.8 Electrical Equipment Insulated with SF₆

The Keasbey Energy Center will include a total of two (2) new circuit breakers for the combined cycle power block. SF₆ emissions from the new circuit breakers are calculated using a predicted SF₆ annual leak rate of 0.5% by weight. The global warming potential factors used to calculate CO₂e emissions are based on 40 CFR Part 98.

2.9 Fuels

CPV Keasbey is proposing to utilize natural gas as the primary fuel for the combustion turbine. The natural gas is assumed to have a HHV of 1,024 Btu/standard cubic foot (scf) and an estimated sulfur content of 0.63 grains per 100 scf and is used for the basis of facility design and by GE in establishing emission calculations. The combustion turbine will also combust ULSD as a backup fuel for up to 720 hours per year.

The emergency diesel engines will also burn ULSD that is stored in two (2) separate day tanks. The ULSD is assumed to have a HHV of approximately 19,649 Btu/lb with a sulfur content of 15 ppm by weight. ULSD firing in the emergency engines will be limited to 100 hours per year per engine.

2.10 Facility Operating Modes

The combined cycle unit will be operated to follow electrical demand (i.e., dispatch mode). The combined cycle unit will not operate at steady-state below 30% load on natural gas and 50% load on ULSD.

2.11 Source Emission Parameters

Emissions of air contaminants from the proposed combined cycle power facility have been estimated based upon expected vendor emission guarantees, control analysis results, emission factors presented in the U.S. EPA publication AP-42, mass balance calculations, and engineering estimates. Emission calculations used to develop the emission estimates for the proposed equipment are included in this application as Appendix B.

2.11.1 Emissions from the Combined Cycle Unit

Emissions from the combined cycle unit will include criteria pollutants, non-criteria pollutants, and hazardous air pollutants (HAPs). Short-term and annual emission rates of these pollutants from the combined cycle unit are described below.

2.11.1.1 Criteria Pollutants

Combustion turbine performance and emissions are affected by ambient temperature, fuel consumption, power output, and fuel type. Proposed emission rates and exhaust characteristics for the combined cycle unit are provided in Appendix B.

Exhaust and emission parameters are presented for the combustion turbine while firing natural gas at different ambient temperatures (-8°F for worst-case winter conditions, 59°F for average annual conditions, and 105°F for worst-case summer conditions), five (5) combustion turbine steady-state loads (30%, 44%, 47%, 75%, and 100%), and operating conditions for HRSG duct firing. A total of sixteen (16) combustion turbine steady-state operating scenarios are presented for natural gas firing.

Exhaust and emission parameters are also presented for the combustion turbine while firing ULSD at different ambient temperatures (-8°F for worst-case winter conditions, 59°F for average annual conditions, and 105°F for worst-case summer conditions) and three (3) combustion turbine steady-state loads (50%, 75%, and 100%). A total of ten (10) combustion turbine steady-state operating scenarios are presented for ULSD firing.

Potential emission rates for NO_x, CO, VOC, SO₂, H₂SO₄, and PM/PM-10/PM-2.5 from the combined cycle unit are based on vendor emissions data.

2.11.1.2 Greenhouse Gases

For PSD purposes, greenhouse gases (GHGs) are a single air pollutant defined as the aggregate group of the following six gases: carbon dioxide (CO₂), nitrous oxide (N₂O), methane (CH₄), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF₆). CO₂, N₂O, and CH₄ are the only pollutants of concern for the combustion turbine unit. Potential emissions of GHGs from the proposed facility are based on vendor guarantees (for CO₂) and 40 CFR Part 98 Emission Factors.

2.11.1.3 HAPs

Appendix B presents a summary table of potential emissions of HAPs from the proposed facility based on U.S. EPA's AP-42 Emission Factor Guidance Document. U.S. EPA's AP-42 emission factor for formaldehyde is expected to be much greater than actual formaldehyde emissions from the use of the GE 7HA.02 or equivalent combustion turbine. Formaldehyde emissions from the combustion turbine while firing natural gas or ULSD are based upon a GE recommended value of 91 ppbvd, which is consistent with the combustion turbine MACT standard. Potential facility formaldehyde emissions are less than 10 tons/yr. Total potential emissions of HAPs from all sources are less than 25 tons/yr. Therefore, the proposed combined cycle power facility will be a minor source for HAP emissions.

2.11.1.4 Other Pollutants

Sulfuric acid mist (H₂SO₄) emissions are based on the mass balance emission calculations for SO₂ and conversion rates of SO₂ to SO₃. The SCR and oxidation catalysts are expected to convert a significant portion of SO₂ to SO₃. Note that calculated potential emissions of SO₂ have not been reduced to reflect SO₂ to SO₃ conversion.

Potential emissions of ammonia (NH₃) are calculated from the proposed maximum ammonia slip emission rate of 5 ppmvd @ 15% O₂ during all operating scenarios.

2.11.2 Auxiliary Boiler Emissions

The Facility is proposing to use one natural gas-fired auxiliary boiler to support start-up and shutdown activities for the combined cycle unit. Short-term potential emission rates are provided based on a combination of equipment vendor design data and fuel sulfur content. GHG emissions from the auxiliary boiler are based on 40 CFR Part 98 Emission Factors. Potential annual emissions are estimated from the operating hours at maximum capacity (4,000 hrs/yr). Potential HAP emissions are based on emission factors from AP-42 Chapter 1.4 (July 1998) and Chapter 1.3 (September 1998). Please see Appendix B for potential emission calculation details.

2.11.3 Emergency Diesel Engines Emissions

CPV Keasbey, LLC is proposing to use two (2) diesel internal combustion engines for the emergency generator and emergency fire pump. Short-term potential emission rates for each engine are provided based on a combination of equipment vendor design data and fuel sulfur content. GHG emissions from the diesel engines are based on 40 CFR Part 98 Emission Factors. Potential HAP emissions are based on emission factors from AP-42 Chapter 3.3 (October 1996). Due to the limited operation of these sources, annual potential-to-emit (PTE) emissions are calculated using the maximum hourly emission rate and 100 hours per year operation per engine. Please see Appendix B for potential emission calculation details.

2.11.4 Cooling Tower Emissions

The proposed cooling tower can potentially emit particulate matter (filterable PM/PM-10/PM-2.5) emissions. Potential emissions of filterable PM/PM-10/PM-2.5 are determined by performing a mass balance calculation using the maximum water flow rate (up to 153,000 gpm), maximum drift rate (0.0005% for high efficiency drift eliminator design), and the maximum circulating water total dissolved solids (TDS)/total suspended solids (TSS) concentration (6,240 ppm). Annual potential emissions are calculated using the maximum hourly emission rate and 8,760 hours per year cooling tower operation. PM-10 and PM-2.5 emissions are calculated using the particulate size distribution recommended in the 2001 Reisman and Frisbie paper “Calculating Realistic PM-10 Emissions from Cooling Towers”. Please see Appendix B for potential emission calculation details.

2.11.5 Modification Total Potential Annual Emissions

Total potential annual emissions for the proposed combined cycle power facility are presented in Table 2-1. Annual emission values in Table 2-1 represent total PTE from all proposed sources and were based on the following worst-case operating scenarios:

- Year-round (8,760 hours), full load operation of the combustion turbine (at 59°F annual mean ambient temperature);
- The full load equivalent of 30 days (720 hours) of ULSD firing for the combined cycle combustion turbine;
- 8,040 hours of duct firing at maximum design firing rate for the combustion turbine;
- A total of 262 annual combined cycle gas fired rapid shutdown/startup events (10 cold starts, 52 warm starts and 200 hot starts, and a total of 10 annual combined cycle ULSD fired rapid shutdown/startup events (2 cold starts, 3 warm, starts, and 5 hot starts);
- 4,000 hours of operation of the auxiliary boiler;

- 100 hours per year of operation of the emergency diesel generator and 100 hours per year of operation of the diesel fire pump engine; and
- A maximum circulating water total dissolved solids (TDS)/total suspended solids (TSS) concentration of 6,240 ppm and 8,760 hours per year cooling tower operation.

To allow for maximum operational flexibility, Keasbey Energy Center requests that any operating limits be based on annual heat input values, rather than operating hours.

To allow for maximum operational flexibility, Keasbey Energy Center is requesting that the permit not contain limits on operating hours for the combustion turbine unit. Instead, the facility will demonstrate compliance with annual tons/year limits based on continuous emission monitoring system (CEMS) data for NO_x and CO, and combustion turbine fuel heat input values and emission factors for other pollutants. A sample monthly calculation based on monthly total heat input and lb/MMBtu emission factors is included below:

$$\text{SO}_2 \text{ (tons/month)} = (\text{X lb/MMBtu} * \text{H}_{\text{CTNG}} + \text{Y lb/MMBtu} * \text{H}_{\text{CTNGDB}} + \text{Z lb/MMBtu} * \text{H}_{\text{CTULSD}}) / 2000$$

lb/ton

Where:

H_{CTNG} = heat input to the combustion turbine per month from natural gas firing with duct burner off, MMBtu, HHV

H_{CTNGDB} = heat input to the combustion turbine per month from natural gas firing with duct burner on, MMBtu, HHV

H_{CTULSD} = heat input to the combustion turbine per month from ULSD firing, MMBtu, HHV

The facility's Data Acquisition and Handling System (DAHS) will track the heat input to the turbine continuously. Monthly emissions will be calculated for each pollutant using pollutant specific emission factors, as above. The pollutant emission factors will be based on permit limits for each operating condition, but stack test based factors will be used if stack testing indicates a lower lb/MMBtu than the permit limits. In this case, the DAHS system will be updated to include these new stack test results.

Monthly emissions for each unit are added to calculate facility-wide monthly emissions. Each month, the monthly total for each pollutant will be added to the total emissions for the previous eleven months to determine a 12-month rolling total.

2.11.6 Total Facility Potential Annual Emissions

The existing CPV Shore, LLC Facility (Woodbridge Energy Center) consists of 2 x GE 7FA.02 combustion turbines with heat recovery and a single steam turbine generator with associated ancillary equipment, is currently permitted to operate the following equipment and operating scenarios.

- Combined Cycle Units Steady-State Basis
- Combined Cycle Units Start-Up/Shutdown
- Auxiliary Boiler
- Fire Water Pump Diesel Engine
- Emergency Diesel Generator
- Cooling Tower

Total potential annual emissions for the currently permitted Woodbridge Energy Center as a combined cycle power generating facility are presented in Table 2-2. The total facility emissions (Woodbridge Energy Center and Keasbey Energy Center combined) are presented in Table 2-3.

**Table 2-1: Summary of CPV Keasbey, LLC Project (Keasbey Energy Center)
Criteria Pollutant and Total HAPs Annual Emissions**

Source	Keasbey Energy Center Potential Annual Emissions (tons/yr)												
	NO _x	CO	VOC	SO ₂	TSP	PM-10	PM-2.5	H ₂ SO ₄	CO2e	NH ₃	Pb	Maximum Individual HAP	Total HAPs
Combined Cycle Unit Steady-State Basis	146.0	82.5	47.3	39.0	66.1	115.7	115.7	25.1	2,357,557.9	125.5	2.7E-02		
Combined Cycle Unit Start-Up/Shutdown ⁽¹⁾	0.2	21.9	1.5	N/A	0.0	0.0	0.0	N/A	N/A	N/A	N/A		
Auxiliary Boiler	1.6	5.4	0.7	0.9	1.0	1.0	1.0	0.07	16,919.6		7.1E-05		
Fire Water Pump Diesel Engine	0.1	0.05	0.01	0.0002	0.004	0.004	0.004	0.00001	18.6		1.6E-06		
Emergency Diesel Generator	0.85	0.48	0.03	0.002	0.03	0.03	0.03	0.00014	118.6		1.0E-05		
Cooling Tower					10.5	6.8	2.6						
Circuit Breakers									18.1				
Fuel Oil Tank			0.23										
Total Project PTE	148.7	110.3	49.9	39.9	77.6	123.6	119.3	25.1	2,374,632.8	125.5	2.7E-02	3.6	8.9

Notes:

- (a) The potential HAP emission calculations presented in Appendix B result in total HAP emissions less than 25 tons/yr. Additionally, potential annual emissions of the maximum individual HAP (hexane) are less than 10 tons/yr.
- (b) Potential annual emissions from the combined cycle unit assume the equivalent of 8,040 hr/yr of combustion turbine operation on natural gas with 8,040 hours per year of duct firing, and the full load equivalent of 720 hours per year of combustion turbine operation on ULSD. To allow for maximum operating flexibility Keasbey Energy Center does not propose to include hourly operating restrictions into the permit, but rather comply through the use of annual heat input calculations.
- (c) Combined cycle unit start-up/shutdown emissions are added to the baseline steady-state PTE values if the total start-up/shutdown emissions are more than the steady-state full-load equivalent during the period of unit off-line downtime and duration of the start-up (and previous shutdown). For start-up/shutdown emissions noted above as “—” for certain pollutants, the start-up/shutdown emissions addition to the baseline steady-state PTE is not applicable since mass emissions of these pollutants are fuel input based (lb/MMBtu) and the full-load, steady-state basis represents the worst-case scenario for PTE emission calculation purposes.

**Table 2-2: Summary of CPV Shore LLC Project (Woodbridge Energy Center)
Criteria Pollutant and Total HAPs Annual Emissions**

Source	Woodbridge Energy Center Potential Annual Emissions (tons/yr)												
	NO _x	CO	VOC	SO ₂	TSP	PM-10	PM-2.5	H ₂ SO ₄	CO2e	NH ₃	Pb	Maximum Individual HAP	Total HAPs
Combined Cycle Units Steady-State Basis	135.2	82.7	27.4	11.2	43.4	92.0	92.0	7.7	2,220,740	126.0	5.0E-03		
Combined Cycle Units Start-Up/Shutdown	10.7	205.4	5.8	N/A	0.0	0.0	0.0	N/A	N/A	N/A	N/A		
Auxiliary Boiler	0.92	3.44	0.14	0.05	0.17	0.46	0.46	0.004	10,718		4.5E-05		
Fire Water Pump Diesel Engine	0.1	0.1	0.01	1.6E-04	0.01	0.01	0.01		17.3		1.5E-06		
Emergency Diesel Generator	1.06	0.10	2.4E-02	1.0E-03	6.6E-03	6.6E-03	6.6E-03		110.6		9.4E-06		
Cooling Tower					10.1	6.6	2.4						
Total WEC PTE	147.9	291.8	33.4	11.3	53.7	99.1	94.9	7.7	2,231,586	126.0	5.1E-03	2.7	10.0

Table 2-3: Summary of Total Facility Criteria Pollutant and Total HAPs Annual Emissions

Source	Total Facility (KEC and WEC) Potential Annual Emissions (tons/yr)												
	NO _x	CO	VOC	SO ₂	TSP	PM-10	PM-2.5	H ₂ SO ₄	CO ₂ e	NH ₃	Pb	Maximum Individual HAP	Total HAPs
Combined Cycle Units Steady-State Basis	281.2	165.2	74.8	50.2	109.5	207.8	207.8	32.8	4,578,297.7	251.5	3.2E-02		
Combined Cycle Units Start-Up/Shutdown ⁽¹⁾	10.8	227.3	7.4	N/A	0.0	0.0	0.0	N/A	N/A	N/A	N/A		
Auxiliary Boiler	2.5	8.8	0.9	0.9	1.2	1.5	1.5	0.07	27,637.7		1.2E-04		
Fire Water Pump Diesel Engine	0.2	0.1	0.02	0.0003	0.01	0.01	0.01	0.00001	35.9		3.1E-06		
Emergency Diesel Generator	1.91	0.58	0.05	0.003	0.03	0.03	0.03	0.00014	229.2		2.0E-05		
Cooling Tower					20.58	13.39	4.99						
Circuit Breakers									18.1				
Fuel Oil Tank			0.2										
Total Facility PTE	296.7	402.1	83.3	51.1	131.3	222.7	214.3	32.8	4,606,219	251.5	3.2E-02	6.3	18.9

3.0 APPLICABLE REQUIREMENTS AND REQUIRED ANALYSES

This section contains an analysis of the applicability of federal and state air quality regulations to the planned 630 MW dual fuel fired combined cycle combustion turbine power facility in Woodbridge Township, Middlesex County, New Jersey. The specific regulations included in this applicability review are the Federal New Source Performance Standards (NSPS), Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NNSR) requirements, Maximum Achievable Control Technology (MACT) applicability for HAPs, Federal Acid Rain Program and NO_x Budget Program requirements, and NJDEP Regulations.

3.1 Federal New Source Performance Standards

The NSPS are technology-based standards applicable to new, modified, and reconstructed stationary sources. The NSPS requirements are established for approximately 70 source categories. Four subparts of these standards apply to the proposed facility: General Provisions (40 CFR 60, Subpart A), Standards of Performance for Stationary Combustion Turbines (40 CFR 60, Subpart KKKK), Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc), and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII).

3.1.1 Subpart A: General Provisions

Each source type that is subject to a NSPS of 40 CFR 60 is also subject to the general provisions of Subpart A. The applicable general provisions of Subpart A are detailed in 40 CFR Parts 60.7 (Notification and Recordkeeping) and 60.8 (Performance Tests).

3.1.2 Subpart KKKK: Stationary Combustion Turbines

On July 6, 2006, the U.S. EPA promulgated Subpart KKKK to establish emission standards and compliance schedules for the control of emissions from new stationary combustion turbines that commence construction, modification, or reconstruction after February 18, 2005. Note that stationary combustion turbines regulated under Subpart KKKK are exempt from Subpart GG requirements, which are applicable to units constructed, modified, or reconstructed prior to February 18, 2005. Additionally, heat recovery steam generators (HRSGs) and duct burners regulated under Subpart KKKK are exempt from the requirements set forth in Subparts Da, Db, and Dc for fossil fuel combustion units.

Subpart KKKK establishes emission limits for NO_x for combustion turbines with a heat input capacity (exclusive of duct burners) greater than 850 MMBtu/hr. During natural gas firing, NO_x

emissions are limited to 15 ppm (dry basis by volume, corrected to 15% O₂) or 0.43 lb/MW-hr of useful output. During ULSD firing, NO_x emissions are limited to 42 ppm (dry basis by volume, corrected to 15% O₂) or 1.3 lb/MW-hr of useful output. Emissions of SO₂ from combustion turbines regardless of fuel type are limited to 0.90 lb/MW-hr gross output or low-sulfur fuel to achieve no greater than 0.060 lb/MMBtu. Subpart KKKK also limits NO_x emissions from associated duct burners (exclusive of emissions from the stationary combustion turbine) to 54 ppmvd @ 15% O₂ or 0.86 lb/MW-hr of useful output. Note that useful output is defined as the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application (i.e., total thermal energy made available for processes and applications other than electrical or mechanical generation).

The Facility's proposed emission rates from the combustion turbine are well below the applicable Subpart KKKK emission standards.

3.1.3 Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

The auxiliary boiler is subject to the provisions of 40 CFR Part 60; Subpart Dc because the maximum heat input capacity is between 10 and 100 MMBtu/hr. Subpart Dc requires an initial notification and one-time opacity test for boilers that operate only on natural gas such as the unit proposed. In addition, records must be maintained regarding the amount of fuel burned on a monthly basis. However, since natural gas is the only fuel burned in the auxiliary boiler, there is no reporting requirement to EPA.

3.1.4 Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII establishes emission standards, fuel sulfur limitations, maintenance requirements, operating limitations, monitoring requirements, and recordkeeping requirements for affected units. An affected unit must be a compression ignition designed internal combustion engine that is new (dates vary between April 1, 2006 and 2007 model year) or reconstructed after July 11, 2006. Keasbey Energy Center will purchase and install two (2) internal combustion diesel engines for the emergency generator and emergency fire pump that will meet the applicability requirements of Subpart IIII. Therefore, the proposed potential emission rates of NO_x, CO, PM-10, and VOC from the emergency diesel engines do not exceed the applicable emission standards set forth in Subpart IIII.

3.1.5 Subpart TTTT: Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units

Subpart TTTT establishes emission standards and electric generation monitoring/record keeping requirement for affected units. These standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that the U.S. EPA has determined has been adequately demonstrated for each type of unit. An affected new source is any newly constructed fossil fuel-fired power plant that commenced construction on or after January 8, 2014 and with newly constructed stationary combustion turbines that have a base load rating for fossil fuels greater than 250 MMBtu/hr and serve a generator capable of selling more than 25 MW-net of electricity to the grid. U.S EPA determined that the BSER for new and reconstructed stationary combustion turbines is natural gas combined cycle (NGCC) technology. The final standard for base load combustion turbines is an emission limit of 1,000 pounds of CO₂ per megawatt-hour on a gross-output basis (lb CO₂/MWhr-g). This standard applies to all sizes of base load units.

The method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electric energy output over a rolling 12-operating-month period. In compliance determinations, sources must incorporate emissions from all periods, including startup or shutdown, during which fuel is combusted and emissions are being monitored, in addition to all power produced over the periods of emissions measurements.

Taking into account the efficiency metric for the combined-cycle power plant of pounds of CO₂ per gross MW-hr of electrical generation, the capability of HRSG duct firing, the inherent degradation in turbine performance over the life of the Facility, the inclusion of startup and shutdowns and part-load operation over the course of a year, and operation on ULSD backup fuel, it has been concluded that the Facility will meet the NSPS TTTT limit on a 12-month rolling average during the lifetime of facility operation.

3.1.6 Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels

Subpart Kb establishes VOC standards for volatile organic liquid storage vessels (including petroleum liquid storage vessels) which commenced construction, reconstruction or modification after July 23, 1984. The Project will include the installation of a new ULSD storage tank, with a capacity of 1,000,000 gallons (3,785 cubic meters (m³)). Subpart Kb exempts storage vessels with capacities greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals. Since the vapor pressure of ULSD is less than 3.5 kilopascals (kPa), Subpart Kb does not apply.

3.2 National Emission Standards for Hazardous Air Pollutants

The National Emissions Standards for Hazardous Air Pollutants (NESHAPs) are emissions standards set by the U.S. EPA for an air pollutant not covered by the National Ambient Air Quality Standards (NAAQS) and that may cause an increase in fatalities or in serious, irreversible, or incapacitating illness. The standards for a particular source category require the maximum degree of emission reduction that the U.S. EPA determines to be achievable, which is known as the Maximum Achievable Control Technology (MACT). These standards are authorized by Section 112 of the Clean Air Act and the regulations are published in 40 CFR Parts 61 and 63. The proposed facility is subject to the following two subparts: General Provisions (40 CFR Part 63, Subpart A) and the emission standards for Reciprocating Internal Combustion Engines (RICE) (40 CFR Part 63, Subpart ZZZZ).

3.2.1 40 CFR Part 63, Subpart A – General Provisions

The emergency diesel generator and fire pump are subject to the general provisions for NESHAPs units in 40 CFR Part 63 Subpart A. These include the requirements for notification, record keeping, and performance testing.

3.2.2 40 CFR Part 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Subpart YYYY establishes national emission limitations and operating limitations for HAP emissions from stationary combustion turbines located at major sources of HAP emissions and requirements to demonstrate initial and continuous compliance with the emission and operating limitations. The Keasbey Energy Center is considered an area source of HAPs since HAP emissions are less than the major source applicability limits under 40 CFR 63.6085(b). Therefore, 40 CFR 63 Subpart YYYY is not applicable.

3.2.3 40 CFR Part 63, Subpart ZZZZ – Reciprocating Internal Combustion Engines

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. An area source is defined as a source which is not a major source of HAP emissions. The proposed emergency diesel generator and fire pump are subject to these rules. By complying with the NSPS Subpart IIII, the units will comply with Subpart ZZZZ.

3.2.4 40 CFR 63 Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters Major Sources

40 CFR 63 Subpart DDDDD, also known as Boiler MACT, regulates HAP emissions from boilers and process heaters at facilities that are a major source of HAP. While Keasbey Energy Center will install an auxiliary boiler, the facility will be an area source of HAP. Therefore, major source Boiler MACT does not apply.

3.2.5 40 CFR 63 Subpart JJJJJJ – Industrial, Commercial, and Institutional Boilers Area Sources

Subpart JJJJJJ regulates HAP emissions from boilers at area sources of HAP. The rule defines boiler as:¹

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.

Gas fired boilers are exempt from this regulation per 40 CFR 63.11195(e). Gas fired boilers are defined as:

Any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

The proposed facility will include one (1) auxiliary boiler that will meet the definition of a gas fired boiler. Therefore, Subpart JJJJJJ does not apply.

3.3 New Jersey Department of Environmental Protection Regulations

Applicable regulations from Chapter 7:27 of the New Jersey Administrative Code are identified below:

- Subchapter 3 “Control and Prohibition of Smoke from Combustion of Fuel” - N.J.A.C. 7:27 - 3.5 limits the opacity from internal combustion engines and stationary combustion turbines to less than 20% opacity, exclusive of condensed water vapor for a period of more than 10 consecutive seconds. The combustion turbine will normally have opacity near zero and it is not expected to exceed even 10% for 10 consecutive seconds.
- Subchapter 4 “Control and Prohibition of Particles Combustion of Fuel” - N.J.A.C. 7:27 - 4.2(a) limits the mass emission of particulates from the proposed combined cycle unit, the auxiliary boiler, the emergency diesel generator, and the emergency diesel fire pump.

The proposed particulate limits from all combustion sources are all well below their respective standards.

- Subchapter 8 “Permits and Certificates” - requires a pre-construction permit to be obtained for a new facility or a minor modification. This application seeks a permit pursuant to Subchapter 22 for the combustion turbine, auxiliary boiler, emergency diesel generator, emergency diesel fire pump, and cooling tower, as a significant modification to an existing Title V facility and is covered by Subchapter 22.
- Subchapter 9 “Sulfur in Fuels” - This subchapter does not limit the sulfur content of gaseous fuels; only liquid and solid fuel sulfur content limits are prescribed. Subchapter 9 limits the sulfur content of ULSD used in the combustion turbine, emergency diesel generator, and fire pump to 15 ppm by weight. Per NSPS Subpart IIII, the Facility is required to use 0.0015% sulfur diesel oil in the emergency diesel generator and emergency diesel fire pump which is well below the Subchapter 9 limit.
- Subchapter 13 “Ambient Air Quality Standards” - The air quality impacts from the proposed facility are predicted not to exceed the standards presented in this subchapter as demonstrated in Section 5 (to be provided).
- Subchapter 16 “Control and Prohibition of Air Pollution by Volatile Organic Compounds” - N.J.A.C. 7:27-16.9 establishes VOC and CO limits of 50 ppm and 250 ppm respectively for a stationary gas turbine. The proposed limits are well below these values for all load cases. The auxiliary boiler is subject to N.J.A.C. 7:27-16.8 which limits VOC and CO emissions to 50 ppm and 100 ppm at 7% oxygen, respectively. The proposed emissions from the boiler are below these limits. Subchapter 16 does not apply to the emergency diesel generator or the emergency diesel fire pump.
- Subchapter 18 “Control and Prohibition of Air Pollution from New or Altered Sources Affecting Ambient Air Quality (Emission Offset Rules)” - Establishes emission offsets and LAER requirements for defined major stationary sources. See Sections 3 and 4 of this application.
- Subchapter 19 “Control and Prohibition of Air Pollution from Oxides of Nitrogen” - Subchapter 19 contains an efficiency limit for natural gas fired combined cycle combustion turbines of 0.75 lb/MW-hr and for ULSD fired combustion turbines of 1.2 lb/MW-hr. In addition, Subchapter 19 limits NO_x emissions for turbines firing ULSD to 0.75 lb/MW-hr during operation on high electric demand days, unless combusting gaseous fuel is not possible due to gas curtailment. The proposed turbine will comply

with these limits. N.J.A.C. 7:27-19.7 limits NO_x emissions from the auxiliary boiler to 0.10 lb/MMBtu. The auxiliary boiler's proposed NO_x limit of 0.01 lb/MMBtu is well below the Subchapter 19 standard. In addition, the boiler is required to be adjusted annually. The emergency diesel generator is only subject to the recordkeeping requirements under N.J.A.C. 7:27-19.11. The emergency diesel fire pump is exempt from these regulations since the maximum power output is less than 500 hp.

- Subchapter 21 "Emission Statements" – The facility will submit an annual emissions statement for each reporting year to the NJDEP in accordance with Subchapter 21.
- Subchapter 22 "Operating Permits" – The facility will file for an operating permit modification which is covered by Subchapter 22.24 Significant modifications.

3.4 Attainment Status and Compliance with Air Quality Standards

The location of the proposed combined cycle power facility in Middlesex County, New Jersey is in an area currently designated as attainment for SO₂, NO₂, CO, PM-10, and PM-2.5. Therefore, for these pollutants, the proposed project is required to demonstrate compliance with the NAAQS and NJAAQS shown in Tables 3-1 and 3-2. Middlesex County is designated as moderate non-attainment for the 8-hour ozone standard. Although the proposed project is located in an area classified as moderate non-attainment for O₃, N.J.A.C. 7:27-18.2 states that an emissions increase of more than 25 tons per year of NO_x or VOC would subject the proposed project to non-attainment NSR for these pollutants. Because the Facility has potential emissions of NO_x and VOC above 25 tons per year, NNSR requirements will apply.

3.5 Prevention of Significant Deterioration

3.5.1 Applicability

The Project is seeking an air permit as a major modification to an existing major source. In this case, fossil fuel steam/electric generating facilities with a heat input capacity of more than 250 MMBtu/hr and criteria pollutant emissions greater than the Significant Emission Rate thresholds as tons per year of any regulated pollutant are subject to PSD review. The Project's emissions of CO, PM-10, PM-2.5, GHG's and H₂SO₄, exceed the applicable SER thresholds and, as such, are required to be reviewed subject to PSD regulation.

On June 3, 2010, EPA issued a final rule that "tailors" the applicability provisions of the PSD program to allow EPA and states to phase in permitting requirements for GHG emissions. This final rule is more commonly known as the "Tailoring Rule." The Tailoring Rule established PSD

applicability for GHG emissions for a new stationary source to be 100,000 tpy, measured as CO₂e.

On June 23, 2014, the Supreme Court of the United States issued a decision with respect to GHG applicability to the PSD program as well as the Title V operating permit program. The decision stated that, “EPA exceeded its statutory authority when it interpreted the Clean Air Act to require PSD and Title V permitting for stationary sources based on their greenhouse gas emissions. Specifically, the Agency may not treat greenhouse gases as a pollutant for purposes of defining a ‘major emitting facility’ (or a ‘modification’ thereof) in the PSD context or a ‘major source’ in the Title V context.” *Util. Air Regulatory Grp. v. EPA*, Case No. 12-1146, Slip Op. at 29 [June 23, 2014]. The decision goes on further to state that, “EPA may, however, continue to treat greenhouse gases as a ‘pollutant subject to regulation under this chapter’ for purposes of requiring BACT for ‘anyway’ sources.” An “anyway” source is defined as a source that would be subject to PSD applicability “anyway” due to PSD applicability of another PSD pollutant. The Keasbey Energy Center is considered an “anyway” source, because the potential emissions of other PSD pollutants are above their respective SERs.

Therefore, based on the U.S. Supreme Court’s decision, the Keasbey Energy Center, including its GHG emissions, is subject to PSD applicability or BACT review. Based on potential to emit, the proposed facility is subject to PSD permitting requirements for CO, PM/PM-10/PM-2.5, H₂SO₄, and GHG emissions.

3.5.2 Requirements

The PSD regulations state that facilities subject to PSD review must perform an air quality analysis (which can include atmospheric dispersion modeling and preconstruction ambient air quality monitoring), and a Best Available Control Technology (BACT) demonstration for those pollutants that exceed the pollutant-specific significant emission rates (SERs) identified in the regulations as well as an additional impacts analysis that examines the impacts of air emissions from the project on visibility, soils, and vegetation.

3.5.2.1 Best Available Control Technology

Keasbey Energy Center must utilize BACT controls for emissions of CO, PM/PM-10/PM-2.5, and H₂SO₄, from each piece of new equipment. As previously stated, BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of energy, economic, and environmental factors. In a BACT analysis, the energy, environmental, and economic factors associated with each alternate control technology are evaluated, in addition to the benefit of reduced emissions that the technology would bring. The BACT analysis for the proposed facility is detailed in Section 4.

3.5.2.2 Air Quality Analysis

The PSD air quality impact analysis (described in detail in Section 5, to be provided) requires dispersion modeling that uses emission rates and stack parameters (stack height and flue gas exit temperature and velocity) coupled with historical meteorology representative of the site to predict the location and magnitude of maximum impacts for various pollutants and averaging periods. If dispersion modeling indicates that the predicted air quality impact concentration of a given pollutant emitted from the proposed facility is lower than its respective Significant Impact Level (SIL) shown in Table 3-1, it is considered to have an insignificant impact and no further air quality analysis is required. If modeled concentrations of one or more pollutants exceed their respective SILs, the proposed facility is considered to have an area of impact and requires additional air quality analysis.

3.5.2.3 Ambient Air Quality Monitoring

Proposed facilities subject to PSD review may have to perform up to one year of preconstruction ambient air quality monitoring for those pollutants emitted in amounts exceeding the PSD SERs shown in Table 1-1, unless granted an exemption by the reviewing agency, NJDEP. Pre-application air quality monitoring guidance can be found in Chapter C, Section III.A of the “New Source Review Workshop Manual”. Pursuant to the PSD regulations codified in 40 CFR 51.166 and 40 CFR 52.21, the PSD preconstruction monitoring requirement may be satisfied with existing monitoring data if these data can be shown to be representative of air quality in the area of the proposed facility.

TRC, on behalf of the Project, submitted a request to the NJDEP for the planned 630 MW (nominal) dual fuel fired combined cycle power facility for an exemption from the requirement to perform one year of pre-construction ambient air quality monitoring at the proposed facility site on July 12, 2016. The request for waiver from pre-construction ambient air quality monitoring can be found in Appendix D.

3.5.2.4 Impact Area Determination

A proposed facility subject to the PSD regulations must determine its impact on air quality for any pollutant for which it does not have an insignificant impact. The area of impact is defined as the greatest distance from the proposed facility site within which the emissions result in concentrations greater than the significant impact concentrations.

3.5.2.5 Additional Impact Analyses

The fact that the proposed facility's potential emissions are greater than the applicable PSD significant emission rate thresholds means that certain additional analyses are required as part of the PSD review. These include modeling to assess potential for impacts to soils and vegetation, visibility, and include emissions from associated industrial, commercial, and residential growth as well as the emissions from the proposed facility. A more detailed explanation of this analysis is presented in Section 5 of this application.

3.5.2.6 Impacts on Class I Areas

Applicants proposing major projects within 300 km of Class I areas may be required to perform an assessment of potential impacts in the Class I areas. The only Class I area within 300 km of the proposed facility is the Brigantine Wilderness area located in the Edwin B. Forsythe National Wildlife Refuge in New Jersey. This area is located approximately 108 km south of the proposed facility. The Federal Land Manager (FLM) for this Class I area was notified by letter on July 12, 2016 and requested to determine if assessments of impacts in the Class I area would be required. In an email dated July 13, 2016, the FLM indicated that no Class I modeling analyses would be necessary. Copies of both the letter and the FLM's response can be found in Appendix D.

3.5.2.7 Environmental Justice

The purpose of the Environmental Justice (EJ) program is to evaluate whether minority and low-income communities are affected adversely or disproportionately by the actions of federal agencies, including approvals under the PSD program. The EJ analysis is presented in Section 6 of this application.

3.5.2.8 Threatened and Endangered Species

Section 7 of the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 et seq.) (ESA), directs all Federal agencies to use their existing authorities to conserve threatened and endangered species and, in consultation with the U.S. Fish and Wildlife Service (USFWS), to ensure that their actions do not jeopardize listed species or destroy or adversely modify critical habitat.

On July 15, 2011, the NJDEP and the EPA executed a Memorandum of Understanding that revised conditions of the PSD delegation agreement. More specifically, condition M of the delegation agreement specifies that "pursuant to Section 7 of the Endangered Species Act (ESA),

16 U.S.C. 1531 et seq, and 50 CFR part 402, Subpart B (“Consultation Procedures”), NJDEP shall:

1. Ensure that the USFWS, U.S. National Marine Fisheries Service (NMFS) or other appropriate Federal Land Manager is notified of each PSD application and a copy of the application is provided if requested;
2. Notify applicants of the potential need for consultation between EPA and USFWS/NMFS if the project may affect any endangered species; and
3. Refrain from issuing a final PSD permit until EPA has notified NJDEP that its obligations under the ESA, if any, have been met.”

During the preparation of this PSD air permit application, TRC consulted with the USFWS to identify potential impacts to federally-listed threatened and endangered species. At this time, the Project will not require in-water activities or activities adjacent to the Raritan River, and, as such, consultation with NMFS was not conducted. If it is determined the Project will require in-water activities or require in-water work within the Raritan River, TRC will consult with NMFS at the appropriate time.

TRC performed a review of potentially federally-listed threatened and endangered species onsite or within the immediate vicinity of the site using the USFWS’ Information Planning and Conservation System (IPAC). An official species list was obtained for the Project from the USFWS on July 5, 2016. The USFWS confirmed there are no federally-listed threatened or endangered species in the vicinity of the Project and there is no critical habitat within the Project area (see Appendix D). As such, no further consultation with the USFWS relative to the ESA is required.

3.6 Non-Attainment New Source (NSR) Review Requirements

3.6.1 Applicability

As stated above, since the proposed facility site is located within a moderate ozone non-attainment area and with potential annual emissions above applicability thresholds for NO_x and VOC, the source is subject to non-attainment NSR.

3.6.2 Requirements

The preconstruction review requirements for major new sources or major modifications located in areas designated non-attainment pursuant to Section 107 of the Clean Air Act Amendments of 1990 (CAAA) differ from the PSD requirements. First, the emissions control requirement for non-attainment areas, LAER, is defined differently and is more stringent than the BACT

emissions control requirement. Second, the source must obtain any required emissions reductions (offsets) of the non-attainment pollutant precursors from other sources which impact the same area as the proposed source. Third, the applicant must certify that all other sources owned by the applicant in the State are complying with all applicable requirements of the CAAA, including all applicable requirements in the State Implementation Plan (SIP). Additionally, per the provisions of N.J.A.C. 7:27-18.3(c)(2), the applicant must perform an analysis of alternate sites, equipment sizes, production processes and environmental control technologies.

3.6.2.1 Lowest Achievable Emission Rate

Pollutants subject to non-attainment NSR must be limited to LAER levels. LAER is defined as either the most stringent emission limitation contained in a SIP (unless it is demonstrated to not be achievable) or the most stringent emission limitation which is achieved in practice by the class or category of source, whichever is the most stringent. Pollutants are subject to LAER if potential emissions of individual pollutants exceed significance levels as defined in N.J.A.C. 7:27-18.2. Based upon these criteria, emissions of NO_x and VOC are subject to LAER requirements. LAER analyses for each piece of new equipment with emissions of NO_x and VOC are presented in Section 4 of this application support document.

3.6.2.2 Emission Reduction Credit Requirements

Emissions reductions must be obtained as a condition for approval to operate a major source or major modification planned in a non-attainment area. The emissions reductions, generally obtained from existing sources located in the vicinity of a proposed source must (1) offset the emissions increase from the new source or modification and (2) provide a net air quality benefit. These offsets, obtained from existing sources that have implemented a permanent, enforceable, quantifiable and surplus emissions reduction, must equal the emission increase from the new source or modification multiplied by an offset ratio, and must provide a net air quality benefit. The New Jersey offset requirements are detailed in N.J.A.C. 7:27-18.5.

The amount of offsets required by the unit is determined by multiplying the proposed potential emissions by the offset ratio. Minimum offsets ratios are presented in N.J.A.C. 7:27-18.5, Table 2, and are based upon the distance of the facility from the source of the emission credits. Based upon these requirements, the minimum offset ratio required is 1.3:1.0. The calculation of required offsets for the facility based upon this minimum offset ratio is presented in Table 3-4. The offsets must be obtained and certified for use prior to commencing operation of the facility.

As listed in Table 3-3, Keasbey Energy Center will require 194 tons of NO_x and 65 tons of VOC emission reduction credits. CPV Keasbey, LLC has retained Emission Advisors, to assist in the procurement of the required offsets to satisfy this regulatory requirement.

3.6.2.3 Compliance Status of Other New Jersey Facilities

CPV Keasbey, LLC does not own or operate any other facilities within the State of New Jersey. The Project is being constructed on property owned by CPV Shore Urban Renewal, LLC, a wholly owned subsidiary of CPV Shore Holdings, LP. A Compliance Certification Statement can be found in Appendix F.

3.6.2.4 Analysis of Alternatives

Based on the provisions of N.J.A.C. 7:27-18.3 (c)(2), Keasbey Energy Center is subject to non-attainment new source review requirements. This section presents the results of our analysis of alternative sites, sizes, production processes and environmental control technologies for the proposed facility. The analysis demonstrates that the benefits of developing the facility at the proposed location significantly outweighs the environmental and social costs imposed as a result of the planned facility's construction and operation in Woodbridge Township, Middlesex County, New Jersey. An analysis of alternate sites, production processes and environmental control technologies, equipment sizes, fuel supplies, and other lower polluting energy generation technologies, such as wind or solar, is presented in Section 3.5.2.4.1 through 3.5.2.4.5.

3.6.2.4.1 Alternative Sites Evaluated

The screening and evaluation for the Keasbey Energy Center was performed when CPV was evaluating sites for the CPV Woodbridge Energy Center. The evaluation process started with identifying the electric market, in this case the PJM regional electric transmission grid and the identification of several properties in New Jersey and Pennsylvania where the sites had access to sufficient industrial zoned land in close proximity to electric transmission lines, fuel, and water. Screening efforts focused on evaluating potential sites from numerous perspectives as well as undertaking preliminary evaluations (e.g., PJM interconnection study, fuels supply, etc.) to identify a Project that would minimize impacts to the environment, be market-driven, create jobs, and facilitate economic development within the State of New Jersey. This evaluation also reflected an assessment relative to an extensive list of criteria that included, but was not limited to, the following:

- Proximity of the project to existing major electric transmission lines and/or substations
- Availability of more than 10 acres of land, preferably zoned industrial and with a buffer from sensitive receptor locations such as schools, hospitals and residences
- Availability of adequate water supply and waste water discharge capacity
- Proximity to and ability to cost effectively obtain required fuel supply interconnections

- Proximity to major roadways and/or railways (to facilitate major equipment delivery and construction needs)
- Availability of a site with minimal or no impacts to wetlands
- Availability of a site with no impacts to threatened and endangered species; and,
- Ability to access an adequate supply of labor for construction and operation phases of the project

Based on the evaluation criteria described above, CPV determined that the property in the Township of Woodbridge, Middlesex County, New Jersey was the optimal site to develop a power generation facility.

Site Ownership

The site for the proposed Project is currently owned by CPV Shore Urban Renewal, LLC. CPV Shore Urban Renewal, LLC is subsidiary of CPV Power Holdings, L.P. which is the parent company for all of CPV's development projects, including CPV Keasbey, LLC.

Zoning

The Keasbey Energy Center will be built on a subdivided parcel, directly adjacent to the recently completed CPV Shore, LLC Woodbridge Energy Center. As one might have assumed with a similar power generation facility adjacent, the development of the site for the Keasbey Energy Center is compatible with existing and planned land uses and local ordinances. The project site is part of the Township of Woodbridge's EPEC Redevelopment Plan. The site is surrounded by properties utilized for a variety of industrial and commercial uses. Current uses in the area surrounding the site include power generation, warehousing and distribution, chemical manufacturing, bulk storage for transport of aggregates and petroleum products, asphalt batch plant operation and light industry. The closest residential area is located approximately 3,000 feet to the north-northeast and is buffered heavily by roads and highways.

Available Space

The Keasbey Energy Center will be built on land that will be subdivided from property that is currently owned by CPV Shore Urban Renewal, LLC and will be adjacent to the existing Woodbridge Energy Center, a nominal 725 MW natural gas fired combined cycle power generation facility. The subdivided property will be approximately 11 acres. The Woodbridge Energy Center was developed and designed to allow for a future expansion. Therefore, there is adequate space for the Keasbey Energy Center to be constructed and operated on the proposed site. The two power generation facilities will be able to utilize some of the same facilities, including a natural gas pipeline and an administrative building.

Proximity to Critical Infrastructure (Electric, Natural Gas, Water Supply, Wastewater Discharge, Labor and Transportation)

As part of the due diligence effort, CPV Keasbey, LLC evaluated the availability of off-site infrastructure necessary to support construction and operation of the proposed Project. This included an assessment of likely off-site interconnection points to satisfy fuel, transmission system delivery, water supply (reclaimed wastewater from Middlesex County Utilities Authority (“MCUA”)) and wastewater disposal requirements. The analysis identified, on a preliminary basis, the potential infrastructure improvements or ancillary facilities necessary, their projected costs and associated environmental permitting requirements. Results are highlighted below:

Off-site infrastructure

Transmission – The facility is located within 2.2 miles of an existing substation (e.g., PSEG Metuchen) which is the preferred tie-in point for the electricity that would be generated by the new combined cycle facility. Electrical interconnection studies are being performed by PJM to identify the network upgrades, improvements and costs for electrically interconnecting at this location. Due to market conditions, this is a different electrical tie-in point than the Woodbridge Energy Center.

Natural Gas – Natural gas will serve the project from the existing Transco lateral that serves the existing Woodbridge Energy Center. This lateral terminates on the site and has enough excess capacity to serve the Keasbey Energy Center.

Reclaimed Water and Wastewater Disposal – The Keasbey Energy Center will utilize reclaimed wastewater supplied by the MCUA to meet the requirements of the facility. The MCUA is located south of the site location, across the Raritan River in Sayreville, Middlesex County, New Jersey. This is the same water treatment plant that serves the Woodbridge Energy Center. A new reclaimed water supply line will need to be built to serve the Keasbey Energy Center.

The ability to use reclaimed water at the facility is advantageous from an environmental perspective. The lack of adequate flow in the rivers, as a result of diversion for industrial purposes, can cause deterioration of water quality and ecosystem health. The use of reclaimed water will also minimize wastewater discharges to the Raritan River from the MCUA. By decreasing wastewater discharges to the Raritan River, the use of reclaimed water at the facility will ultimately contribute to the preservation and enhancement of the Rivers natural, marine habitat. In addition to these environmental benefits, CPV Keasbey, LLC will provide monetary compensation to the MCUA for the reclaimed water to be used at the facility.

CPV Keasbey, LLC will secure its potable water supply via the Middlesex Water Company existing on-site line. Backflow preventers will be constructed at appropriate locations to prevent

cross contamination of potable water and reclaimed water supplies. Process water and sanitary discharges from the plant will be discharged to the Township of Woodbridge sewer system and ultimately back to the MCUA via the Woodbridge Energy Center's existing sanitary sewer line. The MCUA facilities comprise one of the largest sewage plants in the State of New Jersey and are equipped with state-of-the-art technology to treat industrial wastewater. Therefore, the MCUA will have sufficient capacity to treat effluent from the proposed facility.

Labor – There is an adequate labor pool in the area from which to draw on during facility construction and operation. It is anticipated that the required construction labor force for the project will be readily met with the available trades and union workforce in the Middlesex County area without the need for in-migration of construction workers from outside the New Jersey/New York metropolitan area.

Transportation – At the proposed site, sufficient options (i.e., roadways, railways and waterways) during construction for the delivery of equipment, materials and plant components and from employee access once operations commence. Major highways surrounding the Project site include routes I-287, I-95, Route 440 and Route 9. Railroad tracks owned by Consolidated Rail Corporation are located immediately to the north of the site along Industrial Avenue. The Raritan River is south of the site and has a several off-loading areas near the facility site.

3.6.2.4.2 *Alternative Sizes*

Based upon a variety of studies as part of its electric generation development evaluations (e.g., PJM electric interconnect studies, electric pricing, PJM capacity pricing, site availability/space, combustion turbine technology and availability, delivery schedule, cost and operational performances, etc.), CPV Keasbey has determined that the optimal development for the Project site is a nominal 630 MW, dual-fuel, combined cycle power generation facility operating in a 1x1 (i.e., 1 combustion turbine and 1 steam turbine) configuration with a natural gas duct burner. The project evaluated utilizing General Electric ("GE") 7FA.05 combustion turbines (currently operating at the Woodbridge Energy Center), but based on the current PJM pricing model, the desired operating efficiency and performance of the combustion turbine, the availability, and the cost, CPV Keasbey selected the GE 7HA.02 machine for the proposed Project. The GE 7HA.02 combustion turbine is the cleanest, most efficient combustion turbine available today.

3.6.2.4.3 Production Process and Fuel Supply

The Project is designed primarily as a natural gas fired combined cycle facility with the ability to use ultra-low sulfur diesel (ULSD) as a backup fuel source to enhance reliability. The use of modern combined cycle technology promotes the efficient utilization of fuel for electric generation. Increasing fuel efficiency favorably affects the cost of generating electricity. The proposed Keasbey Energy Center has been designed to meet the objective of providing reliable, efficient, economical and environmentally safe electricity to meet the current and future demands for electric generation capacity in the State of New Jersey.

With its design reflecting the storage and use of ULSD, Keasbey Energy Center will be able to provide a sustained and predictable supply of electric capacity to the PJM system, especially when other PJM generation assets may not be available to deliver power due to the impacts of extended cold temperatures (e.g., unprecedented forced outage rates were experienced by power generators during recent winters). Finally, the Project's dual fuel capability will also satisfy the Federal Energy Regulatory Commission's PJM Capacity Performance Filing of 12/12/14, as amended in April 2015.

3.6.2.4.4 Alternative Energy Generation Technologies Consideration

CPV Keasbey evaluated the environmental, economic, and social costs for the development/construction of alternative energy generation technologies at the existing CPV Shore site. The conclusion was that development of the previously planned-for combined cycle electric generation plant at this location was the most effective way to revitalize and redevelop the area. Development of wind energy is not a viable option due to the lack of sustainable wind resources and available space on the property. Likewise, development of the site with solar panel arrays is an option that CPV Keasbey has evaluated. However, this is not viable due to lack of sufficient space to generate an equivalent 630 MW. Further, it is not an efficient use of the land, based on the MW/acre energy generating density offered by photovoltaic panels. The original development project (Woodbridge Energy Center) proposed economic justification and the Township's expectations relative to the subsequent future development of the site reinforced CPV Keasbey's plans to develop a second combined cycle power plant project at this location.

3.6.2.4.5 Environmental Control Technologies

Based upon the Project's site location and non-attainment status, the premise for development of the Keasbey Energy Center is that it would be designed to meet federal BACT and Lowest LAER standards to comply with PSD requirements, NSR requirements, and New Jersey SOTA requirements. The facility's design reflects the following:

- Utilization of the highly efficient GE 7HA.02 combustion turbine.
- Dry low NO_x combustion technology for the combustion turbine (during natural gas firing), water injection (during ULSD firing), and selective catalytic reduction system (SCR) for NO_x control.
- An oxidation catalyst for CO and VOC control.
- Natural gas and ULSD to minimize emissions of SO₂ and PM/PM-10/PM-2.5.
- A cooling tower design that will include high efficiency drift eliminators that are designed to meet 0.0005% control efficiency.
- Utilization of aqueous ammonia (at 19.5%) as opposed to anhydrous ammonia for the SCR system.
- Lastly, the Project's engineering design reflects the planned use of treated wastewater effluent (gray water) from the Middlesex County Utilities Authority regional wastewater treatment plant which is consistent with the New Jersey Department of Environmental Protection's policy of encouraging the use of reclaimed water for beneficial reuse.

3.6.2.4.6 Environmental/Social Costs and Benefits of the Proposed Facility

The proposed Keasbey Energy Center meets or exceeds key objectives articulated by New Jersey State officials for projects that are market driven, create jobs, and produce economic development within the State and Middlesex County. The proposed Project also satisfactorily addresses the evaluation criteria detailed above. These include:

- Construction of the proposed Project will require an average work force of 500-600 people during the 30-month construction schedule.
- The facility, once operational, will employ up to an additional six (6) Full Time Equivalent (FTE); total FTEs at the combined facility will be 28 skilled staff for facility operations.
- There will be minimal, if any, impact on local roadways after construction.
- Middlesex County Utilities Authority, will receive additional revenue for water supply as part of an agreement between Keasbey Energy Center and the Authority.
- The facility's engineering design will ensure compliance with BACT, LAER, and New Jersey SOTA regulatory requirements.
- The Project will have minimal or no impacts on wetlands. It also is not anticipated to impact scenic, recreational, or cultural resources.
- The Project will comply with both state and local noise requirements.
- The Project is located in an ozone non-attainment area and will purchase emission reduction credits for NO_x and VOC at a ratio of 1.3 to 1.0.

- Woodbridge Township will receive an annual payment pursuant to an executed Payment In-Lieu of Taxes (PILOT) Agreement.

3.7 Cross State Air Pollution Rule

U.S. EPA finalized the Cross State Air Pollution Rule (CSAPR) in July 2011 as a replacement for the Clean Air Interstate Rule (CAIR). On December 30, 2011, the D.C. Circuit stayed the rule two days before it was set to go into effect, ordering the EPA to continue administering the previously promulgated CAIR until a final decision could be made on the merits of CSAPR. On August 21, 2012, the U.S. Court of Appeals for the District of Columbia vacated CSAPR in a 2-1 decision. In the August 21, 2012 Order, the panel held that CSAPR exceeded the EPA's statutory authority under the Clean Air Act in two ways: (1) the court determined that CSAPR may require upwind states to reduce their emissions by more than their own significant contributions to a downwind state's nonattainment, contrary to the statute, and (2) the court found that the EPA lacked authority to implement the required emissions reductions through Federal Implementation Plans (FIPs), rather than affording the states an initial opportunity to implement the reductions through State Implementation Plans (SIPs).

On October 5, 2012, the EPA filed a petition with the U.S. Court of Appeals for the District of Columbia requesting en banc rehearing of its ruling on CSAPR, which was denied. However, on June 24, 2013, the U.S. Supreme Court granted EPA's petition to review the D.C. Court of Appeals' decision. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing the August 21, 2012 D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted EPA's request. Accordingly, CSAPR Phase 1 implementation began on January 1, 2015, with Phase 2 beginning in 2017. Similar to other trading programs, CSAPR establishes an allowance trading system to reduce emissions NO_x and SO₂ from power plants. EPA established individual state emissions budgets based on the emissions reductions that each upwind state must achieve to prevent it from unlawfully interfering with other states efforts to achieve the NAAQS. CSAPR also includes an "assurance provision" which requires a state's covered sources to surrender additional allowances if the state's overall emissions threshold is exceeded.

3.8 Greenhouse Gas Monitoring

On September 22, 2009, EPA promulgated the final 40 CFR Part 98 greenhouse gas monitoring and reporting regulations that require approximately 10,000 facilities to report their greenhouse gas (GHG) emissions annually. The reporting rule generally applies to facilities that emit more than 25,000 tons of GHG a year and identifies 29 specific categories of covered sources, such as oil refineries, pulp and paper manufacturing, landfills, manure management, and producers of

aluminum, cement, iron and steel, glass, and various chemicals, as well as a residual category for facilities with large stationary fuel burning sources. Covered facilities started monitoring on January 1, 2010. The proposed facility is subject to the federal GHG Monitoring requirements and will meet them through use of 40 CFR Part 75 monitoring methodologies.

3.9 Section 112(r) Applicability

Aqueous ammonia will be used as the reducing agent in the project's SCR system for controlling NO_x emissions from the combustion turbine. The NO_x reduction achieved by the SCR system is affected by the ratio of ammonia (NH₃) to NO_x. Section 112(r) of the Clean Air Act and the U.S. EPA's Risk Management Program regulations (40 CFR Part 68) require modeling a catastrophic release of any stored ammonia at 20% concentration or above in order to ensure the protection of the off-site public. Furthermore, based on the "general duty" clause of Section 112(r), such analyses can be required even if the aqueous ammonia solution is diluted below 20%. Keasbey Energy Center proposes to store aqueous ammonia at a maximum ammonia concentration of 19.5% or less as the means of complying with Section 112(r).

Table 3-1: National Ambient Air Quality Standards, PSD Increments, Significant Monitoring Concentrations, and Significant Impact Levels

Pollutant	Averaging Period	NAAQS^a (µg/m³)	Class II PSD Increment (µg/m³)	Significant Monitoring Concentrations (µg/m³)	Significant Impact Level (µg/m³)
Carbon Monoxide	1-Hour	40,000	--	--	2,000
	8-Hour	10,000	--	575	500
Nitrogen Dioxide	1-Hour	188	--	--	7.5
	Annual	100	25	14	1
Ozone (VOC)	8-Hour	160	--	--	--
Coarse Particulate Matter (PM-10)	24-Hour	150	30	10	5
	Annual	--	17	--	1
Fine Particulate Matter (PM-2.5)	24-Hour	35	9	4	1.2
	Annual	12	4	--	0.3
Sulfur Dioxide	1-Hour	197	--	--	7.9 ^b
	24-Hour	--	91	13	5
	Annual	80	20	--	1
	3-Hour	--	512	--	25
Lead	3-Month	0.15	--	0.1	--

Notes:

(--) indicates there are no standards for this pollutant.

^aAll short-term (1-hr, 3-hr, 8-hr, and 24-hr) standards except ozone, PM-2.5, PM-10, and 1-hour SO₂ and NO₂ are not to be exceeded more than once per year. For 8-hr ozone, EPA uses the average of the annual 4th highest 8-hour daily maximum concentrations from each of the last three years of air quality monitoring data to determine a violation of the standard. For 24-hour PM-10, EPA uses the 6th highest 24-hour maximum concentration from the last three years of air quality monitoring data to determine a violation of the standards. For 24-hour PM-2.5, EPA uses the 98th percentile 24-hour maximum concentration from the last three years of air quality monitoring data to determine a violation of the standard. For the 1-hour NO₂ NAAQS, compliance would be determined by the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area and for the 1-hour SO₂ NAAQS, compliance would be determined with the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area.

^bInterim SIL per August 12, 2010 memorandum "Guidance Concerning the Implementation of the 1-hour SO₂ NAAQS for the Prevention of Significant Deterioration Program" from Steven Page (Director of U.S. EPA OAQPS).

Table 3-2: New Jersey Ambient Air Quality Standards

Pollutant	Standard	Averaging Period	NJAAQS^a (ug/m³)
Sulfur Dioxide	Primary	12-month arith. mean	80
	Primary	24-hour average	365
	Secondary	12-month arith. mean	60
	Secondary	24-hour average	260
	Secondary	3-hour average	1,300
Total Suspended Particulates	Primary	12-month geom. mean	75
	Primary	24-hour average	260
	Secondary	12-month geom. mean ^b	60
	Secondary	24-hour average	150
Carbon Monoxide	Primary & Secondary	8-hour average	10,000
	Primary & Secondary	1-hour average	40,000
Ozone ^c	Primary	Max. daily 1-hour average	235
	Secondary	1-hour average	160
Nitrogen Dioxide	Primary & Secondary	12-month arith. mean	100
	NJDEP Guideline	1-hour average	470
Lead	Primary & Secondary	Rolling 3-month average	1.5

Notes:

^aNew Jersey short-term standards are not to be exceeded more than once in any 12 month period. Long-term standards are never to be exceeded.

^bIntended as a guideline for achieving short-term standard.

^cMaximum daily 1-hour average: averaged over a three year period, the expected number of days above the standard must be less than or equal to 1.

Table 3-3: Emission Reduction Credits Required for Keasbey Energy Center

Pollutant	Proposed Facility Potential Emissions (tons/yr)	Minimum Offset Ratio	Minimum Required ERC's (tons)
NO _x	148.7	1.3 to 1	194
VOC	49.9	1.3 to 1	65

4.0 CONTROL TECHNOLOGY ANALYSIS

4.1 Overview

Pre-construction review for new major stationary sources located in the State of New Jersey involves an evaluation of Best Available Control Technology (BACT), Lowest Achievable Emission Rate (LAER) technology and/or State-of-the-Art (SOTA). If an area is designated by U.S. EPA as attainment or unclassifiable for a particular pollutant, then new major sources will require permitting under the Prevention of Significant Deterioration (PSD) program, including a BACT demonstration for pollutants emitted in quantities greater than the regulatory thresholds. However, if an area is designated by U.S. EPA as non-attainment for a given pollutant and the major source has the potential to emit the non-attainment pollutant at levels greater than the pollutant-specific regulatory thresholds, then non-attainment new source review (NSR) applies. NNSR requires the application of LAER technology and the requirement to obtain emission offsets. If the proposed project's emissions increase exceeds NJDEP's SOTA threshold for regulated pollutants, SOTA requirements will also apply.

A control technology analysis has been performed for the proposed Facility based upon guidance presented in the draft U.S. EPA Guidance Document *New Source Review Workshop Manual*, (October 1990) and the NJDEP's *State of the Art (SOTA) Manual for Combustion Turbines* (December 21, 2004).

Note that throughout this section, "ppm" concentration levels for gaseous pollutants are parts per million by volume, dry basis, corrected to 15% O₂ content (ppmvd @ 15% O₂), unless otherwise noted. Likewise, all emission factors expressed as pounds of pollutant per million Btu of fuel (lb/mmBtu) are based upon the HHV of the fuel.

4.2 Applicability of Control Technology Requirements

An applicability determination, as discussed in this section, is the process of determining the level of emission control required for each applicable air pollutant. Control technology requirements are generally based upon the potential emissions from the new or modified source and the attainment status of the area in which the source is to be located. A detailed determination of applicable regulations, including control technology requirements under the PSD and non-attainment rules, is provided in Section 3 of this application. The following sections discuss the applicability of BACT, LAER, and additional NJDEP requirements for emissions from equipment included in this permit application.

4.2.1.1 PSD Pollutants Subject To BACT

Pollutants subject to PSD review are subject to a BACT analysis. BACT is defined as an emission limitation based on the maximum degree of reduction, on a case-by-case basis, taking into account energy, environmental and economic considerations. The proposed Facility is considered a “major” modification to an existing major source for PSD purposes since potential emissions exceed Significant Emission Rate thresholds. Therefore, individual regulated pollutants are subject to BACT requirements if potential emissions exceed the significant emission rates presented in 40 CFR 52.21(b) (23) in a PSD (attainment) area, as presented in Table 1-1. Based upon these criteria, NO_x, CO, PM/PM-10/PM-2.5, H₂SO₄, and GHG are all subject to BACT requirements. Since the area is designated attainment for NO₂, NO_x emissions are subject to BACT, as well as the more stringent LAER requirements under the ozone non-attainment provisions, since NO_x is also a precursor for ozone formation and subject to non-attainment NSR. Since LAER technology is generally at least as stringent as BACT, the LAER analysis will satisfy the BACT requirements for NO_x.

4.2.1.2 Non-Attainment Pollutants Subject To LAER

Pollutants subject to NNSR must be limited to LAER levels. LAER is defined as the more stringent of (1) the most stringent emission limitation which is achieved in practice by the class or category of source or (2) the most stringent emission limitation contained in the applicable State Implementation Plan (SIP) (unless such emission rate is demonstrated not to be achievable), whichever is more stringent. LAER will be based upon the lowest permitted emission rates that are verified as being achieved in practice, as discussed in the appropriate section by pollutant. Pollutants are subject to LAER if potential emissions of individual pollutants exceed area-specific emission thresholds. Although the proposed project is located in an area classified as moderate non-attainment for O₃, N.J.A.C. 7:27-18.2 states that an emissions increase of more than 25 tons per year of NO_x or VOC (listed in Table 1-1) will subject the proposed Project to non-attainment NSR and LAER for these pollutants. Based upon these criteria, emissions of NO_x and VOC are subject to LAER requirements.

4.2.1.3 Pollutants Subject to SOTA

SOTA is a New Jersey State requirement that is defined as equipment, devices, methods or techniques as determined by the NJDEP which will prevent, reduce or control emissions of an air contaminant to the maximum degree possible and which are available or may be made available. SOTA for most sources is well defined based upon previous permitting efforts or emission levels presented in NJDEP SOTA Manuals. As defined in Section 1.4 of the SOTA Manual (July 1997), compliance with SOTA requirements can be shown through documentation of compliance with emission levels or technology requirements defined in an applicable SOTA

Manual. Pollutants for which potential emissions are below 5 tons per year (TPY) are not subject to NJDEP SOTA requirements. Pollutants subject to LAER, BACT, or NSPS (promulgated on or after August 2, 1995) meet or exceed New Jersey SOTA requirements. Those emissions of pollutants not subject to BACT, LAER, or NSPS are subject to SOTA requirements. For the proposed facility, pollutants subject to SOTA only include ammonia (NH₃) and opacity from turbine operations. Note that since emissions of ammonia from the ammonia storage tank are less than 5 TPY, the storage tank is not subject to the SOTA provisions. Additionally, SOTA requirements for opacity emissions have been addressed in Section 4.11.

4.3 Approach Used in BACT Analysis

PSD BACT as defined in 40 CFR 52.21 means:

“an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source 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.”

Typically, PSD BACT follows a five step “top-down” approach: (1) identify all control technologies; (2) eliminate technically infeasible options; (3) rank remaining control technologies by control effectiveness; (4) evaluate most effective controls and document results; and (5) select BACT.

However, a key exception to the strict, five-step “top-down” approach is described in page B-8 of the U.S. EPA’s October 1990 draft New Source Review Workshop Manual (the “NSR Manual):

“If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record.

Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT."

The BACT analysis for the planned Keasbey Energy Center Project was conducted consistent with the above definition as well as U.S. EPA's five step "top-down" BACT process. This methodology results in the selection of the most stringent control technology in consideration of the technical feasibility and the energy, environmental, and economic impacts. Control options are first identified for each pollutant subject to BACT and evaluated for their technical feasibility. Options found to be technically feasible are ranked in order of their effectiveness and then evaluated for their energy, economic, and environmental impacts. In the event that the most stringent control identified is selected, no further analysis of impacts is performed. If the most stringent control is ruled out based upon economic, energy, or environmental impacts, the next most stringent technology is similarly evaluated until BACT is determined.

After establishing the baseline emissions levels required to meet any applicable New Source Performance Standards (NSPS), National Emissions Standards for Hazardous Air Pollutants (NESHAPs), or SIP limitations, the "top-down" procedure followed for each pollutant subject to BACT is outlined as follows:

Step 1: Identify available control options from review of U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC), agency permits for similar sources, literature review, and contacts with air pollution control system vendors.

Step 2: Eliminate technically infeasible options - evaluation of each identified control to rule out those technologies that are not technically feasible (i.e., not available and applicable per USEPA guidance).

Step 3: Rank remaining control technologies - "Top-down" analysis, involving ranking of control technology effectiveness.

Step 4: Evaluate most effective controls and document results - Economic, energy, and environmental impact analyses are conducted if the "top" or most stringent control technology is not selected to determine if an option can be ruled out based on unreasonable economic, energy or environmental impacts.

Step 5: Select the BACT based upon the highest ranked option that cannot be eliminated, which includes development of an achievable emission limitation based on that technology.

As previously stated, BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of energy, economic and environmental factors. The BACT analyses may include reductions achieved through the application of processes, systems, and techniques for the control of each air pollutant. U.S. EPA has placed potentially applicable control alternatives identified and evaluated in the BACT analysis into the following three categories:

- (1) Inherently lower-emitting processes/practices/designs;
- (2) Add-on controls, and;
- (3) Combinations of (1) and (2).

4.3.1 Inherently lower-emitting processes/practices/designs

Lower-polluting processes (including design considerations) should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels.

4.3.1.1 Change in raw materials

This emissions limiting technique typically applies to industrial processes that use chemicals, such as solvents, where substitution with a lower emitting chemical may be technically feasible. In the case of the proposed Project, the “raw material” is the fuel combusted for the generation of electricity. The Project proposes the primary use of natural gas with back-up ULSD operation as BACT for the combustion turbine.

4.3.1.2 Process Modifications

Process modifications may be implemented if a change in the process methods or conditions can result in lower emissions. In the case of the Project, the “process” is the combustion turbine firing natural gas or ULSD. The GE 7HA.02 combined cycle technology is among the most efficient fossil fuel power plant designs currently available. Therefore, process modifications beyond what is already proposed are not technologically feasible.

4.3.2 Technically Feasible Add-on Control Options

The first step is identification of available technically feasible control technology options, including consideration of transferable and innovative control measures that may not have previously been applied to the source type under analysis. The minimum requirement for a BACT proposal is an option that meets federal NSPS limits or other minimum state or local requirements that would prevail in the absence of BACT decision-making such as NJDEP SOTA

emission standards. After elimination of technically infeasible control technologies, the remaining options are ranked by control effectiveness.

If there is only a single feasible option, or if the applicant is proposing the most stringent alternative, then no further analysis is required. If two or more technically feasible options are identified, the next three steps are applied to identify and compare the economic, energy, and environmental impacts of the options. Technical considerations and site-specific sensitive issues will often play a role in BACT determinations. Generally, if the most stringent technology is rejected as BACT, the next most stringent technology is evaluated, and so on.

In order to identify options for each class of equipment, a search of the U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) has been performed. Individual searches have been performed for each pollutant (subject to BACT/LAER) emitted from each emissions unit. The most recently issued permits for GE 7HA.02 combustion turbines not yet on the RBLC were also analyzed. Results of the RBLC and the review of other recent permits are summarized in Appendix C.

4.3.2.1 Economic (Cost-Effectiveness) Analysis

This analysis consists of estimation of costs and calculation of the cost-effectiveness of each control technology, on a dollar per ton (\$/ton) of pollution removed basis. Annual emissions of an option are subtracted from base case emissions to calculate tons of pollutant controlled per year. The base case may be uncontrolled emissions or the maximum emission rate allowable without BACT considerations that would generally correspond to an NSPS or SOTA level. Annual costs, in dollars per year (\$/yr), are calculated by adding annual operation and maintenance costs to the annualized capital cost of an option. Cost-effectiveness (\$/ton) of an option is simply the equivalent annual cost (\$/yr) divided by the annual reduction in emissions (ton/yr).

Note that no economic analysis is required if either the most effective option is proposed or if there are no technically feasible control options.

4.3.2.2 Energy Impact Analysis

Two forms of energy impacts that may be associated with a control option can normally be quantified. Increases in energy consumption resulting from increased heat rate may be shown as incremental Btu's or fuel consumed per year. Also, the installation of a control option may reduce the output and/or reliability of the proposed equipment. This reduction would also result in loss of revenue from power sales.

4.3.2.3 Environmental Impact Analysis

The primary focus of the environmental impact analysis is the reduction in ambient concentrations of the pollutant being emitted. Increases or decreases in emissions of other criteria or non-criteria pollutants may occur with some technologies, and should also be identified. Non-air related impacts, such as solid waste disposal and increased water consumption/treatment, may be an issue for some projects and control options.

4.3.3 Achievability

BACT and LAER are based on the premise that the limit established through the respective process must be achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life.

The U.S. EPA has reached the following conclusion in prior determinations for PSD permits:

“Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.”²

Therefore, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

In addition, emission limits from existing permitted facilities must be used with caution in assessing what is "achievable." For example, limits established for facilities that were never built must be viewed with caution, as they have never been demonstrated and that facility/company/applicant never took a significant liability in having to meet that limit. Likewise, permitted units that have not yet commenced construction must also be viewed with caution for similar reasons.

² EPA Environmental Appeals Board Decision, In re: Newmont Nevada Energy Investment LLC PSD Appeal No. 05-04, decided December 21, 2005.

4.3.4 BACT Proposal

The determination of BACT for each pollutant from a given emission unit is based on a review of the above-listed impact categories and the technical factors that affect feasibility of the control alternatives under consideration. The methodology described above is applied to the proposed Project for the pollutants specified in Section 4.2.1.1.

4.4 LAER/BACT Analysis for Nitrogen Oxides

This section presents LAER and BACT determinations for control of NO_x emissions from the combined cycle combustion turbine and duct burner, the auxiliary boiler, the emergency diesel generator, and the emergency diesel fire pump. For each type of equipment, alternative control technologies are evaluated and existing permit limits for units in the same source categories are identified.

As previously discussed, a LAER determination for a source category is based upon the more stringent of either 1) the most stringent emission limitation contained in the SIP for such class or category of source or 2) the most stringent emission limitation achieved in practice by such class or category of source unless demonstrated to not be achievable. To determine the most stringent permit limit, a search of the RBLC and recently issued applicable air permits was performed. The results of the search are presented in Section 4.4.1 and Appendix C.

The formation of NO_x in combustion units is determined by the interaction of chemical and physical processes occurring within the combustion chamber. There are two principal forms of NO_x, designated as “thermal” NO_x and “fuel” NO_x. Thermal NO_x formation is the result of oxidation of atmospheric nitrogen contained in the inlet gas in the high temperature, post flame region of the combustion zone. The major factors influencing thermal NO_x formation are temperature, concentrations of nitrogen and oxygen in the inlet air and residence time within the combustion zone. Fuel NO_x is formed by the oxidation of fuel bound nitrogen. NO_x formation can be controlled by adjusting the combustion process and/or by installing post combustion controls. Section 4.4.2 provides a technical description of NO_x control techniques for all the applicable equipment and the relative availability and suitability for the proposed Project.

4.4.1 Review of NO_x RBLC Database

4.4.1.1 Combined Cycle Combustion Turbine

A search of the RBLC and available permits identified numerous recent natural gas-fired combined cycle combustion turbine projects with NO_x emissions limits of 2.0 ppm. All of the

projects permitted for a NO_x emission limit of 2.0 ppm use selective catalytic reduction (SCR) in addition to dry low-NO_x (DLN) or low-NO_x burner (LNB) technology. No permit was found with an emissions level below 2 ppm. The remaining projects have limits between 2.5 and 15 ppm.

For ULSD firing, there are far fewer recently permitted combined-cycle combustion turbine projects. The most recently permitted combined-cycle combustion turbines firing ULSD are permitted with NO_x emissions limits ranging from 4.0 ppm to 10.0 ppm. All of the projects permitted at these levels use SCR in addition to DLN or LNB technology.

4.4.1.2 Auxiliary Boiler

An RBLC search of recent air permits for natural gas-fired boilers between 10 and 100 mmBtu/hr identified numerous projects with NO_x emissions limits ranging from 0.01 lb/mmBtu to 0.05 lb/mmBtu with a majority of the recently permitted projects having NO_x emissions of 0.011 lb/MMBTU. All of the projects permitted at these levels utilize LNB technology.

4.4.1.3 Emergency Diesel Engines

The RBLC indicates that the range of permitted NO_x limits for diesel engines similar to the Project's emergency diesel fire pump are 0.57 to 4.43 lb/mmBtu, as summarized in Appendix C. The range of permitted NO_x limits for diesel engines similar in size to the Project's emergency diesel generator are 0.01 to 4.43 lb/mmBtu, as summarized in Appendix C.

4.4.2 Identification of NO_x Control Options and Technical Feasibility

The following sections detail the options that were identified for controlling NO_x emissions from the combined cycle combustion turbine, auxiliary boiler, and emergency diesel engines. Their technical feasibility and respective level of commercially demonstrated NO_x reduction of each option is also discussed.

4.4.2.1 Combined Cycle Combustion Turbine

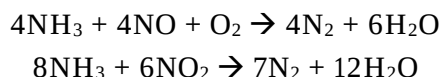
The following control technologies for NO_x were evaluated: Lean Burn Combustion, Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), XONON™ and SCONOX™.

Lean Burn Combustion – Typical gas turbines are designed to operate at a nearly stoichiometric ratio of fuel and in the combustion zone, with additional air introduced downstream. This is the point where the highest combustion temperature and quickest combustion reactions (including NO_x formation) occur. Fuel-to-air ratios below stoichiometric

are referred to as fuel-lean mixtures (i.e., excess air in the combustion chamber); fuel-to-air ratios above stoichiometric are referred to as fuel-rich (i.e., excess fuel in the combustion chamber). The rate of NO_x production falls off dramatically as the flame temperature decreases. Thus, very lean, dry combustors can be used to control emissions.

Based upon this concept, lean combustors are designed to operate below the stoichiometric ratio, thereby reducing thermal NO_x formation within the combustion chamber. The lean combustors typically are two-staged, premixed combustors designed for use with natural gas fuel. The first stage serves to thoroughly mix the fuel and air and to deliver a uniform, lean, unburned fuel-air mixture to the second stage.

Selective Catalytic Reduction (SCR) – SCR is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine/duct burner. SCR involves the injection of ammonia (NH₃) into the exhaust gas stream upstream of a catalyst bed. On the catalyst surface, ammonia reacts with NO_x contained within the flue gas to form nitrogen gas (N₂) and water (H₂O) in accordance with the following chemical equations:



The catalyst's active surface is usually a noble metal (platinum), base metal (titanium or vanadium) or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogenous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path in order to achieve maximum conversion efficiency and minimum back pressure on the gas turbine/duct burner. The most common configuration is a "honeycomb" design. Ammonia is then fed and mixed into the combustion gas stream upstream of the catalyst bed. Excess ammonia (NH₃) that does not react in the catalyst bed and that is emitted from the stack is referred to as ammonia slip.

An important factor that affects the performance of an SCR is operating temperature. The temperature range for standard base metal catalysts is between 400 and 800°F. Since SCR's effective temperatures are below the turbine exit temperature and above the stack temperature, the catalyst must be located within the HRSG.

An undesirable side-effect of SCR is the potential formation of ammonium bisulfate (NH₄HSO₄) and ammonium sulfate ((NH₄)₂SO₄), referred to as ammonium salts, which are corrosive and can stick to the heat recovery surfaces, duct work, or stack at low temperatures and results in

additional PM/PM-10/PM-2.5 formation if emitted. Ammonium bisulfate and ammonium sulfate are reaction products of SO₃ and ammonia. Use of low sulfur fuels minimizes the formation of SO₃ and the subsequent formation of these ammonium salts.

Selective Non-Catalytic Reduction (SNCR) – SNCR is another method of post-combustion control of NO_x emissions. SNCR selectively reduces NO_x into nitrogen and water vapor by reacting the flue gas with a reagent. The SNCR system is dependent upon the reagent injection location and temperature to achieve proper reagent/flue gas mixing for optimum NO_x reduction. SNCR systems require a fairly narrow temperature range for reagent injection in order to achieve a specific NO_x removal efficiency. The optimum temperature range for ammonia injection is 1,500 to 1,900°F. The NO_x removal efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. Operation below this temperature window results in excessive ammonia slip. Operation above the temperature window results in increased NO_x emissions.

Because the exhaust temperature at the exit of the Project's combustion turbine unit is around 1,000 to 1,200°F, which is significantly less than the optimum temperature range for the application of this technology, it is not technically feasible to apply this technology to this Project and it will be eliminated from further evaluation in this LAER analysis.

XONON™ – A NO_x control technology has been developed by Catalytica Energy Systems, with the trade name of XONON™. This combustion technology includes a pre-burner, a fuel injection and mixing system, a flameless catalyst module and a flameless burnout zone. The pre-burner starts the turbine and a fuel injection system provides a uniform fuel and air mixture to the catalyst, where a portion of the fuel is combusted at reduced temperature to reduce thermal NO_x emissions. Catalytica has reported NO_x emissions at less than 3 ppm at 15 percent O₂ from test units under 2 MW. The first commercial version of the XONON™ combustion system is operating in a 1.55 MW gas turbine in Santa Clara, CA. This system has demonstrated NO_x emission levels of less than 2.5 ppm.

The XONON™ system is not yet commercially available from Catalytica Energy Systems for turbines of the size proposed for the Project. However, in December 2000, the California Energy Commission approved the construction of a 750-MW facility in Bakersfield, California. The Pastoria Energy Facility (Pastoria) proposed to use the XONON™ system as BACT to control NO_x emissions from three large combined cycle combustion turbines. The approval was based on the anticipation that the XONON™ technology would be available by the time installation of the Project components was scheduled. If XONON™ was not available in time, Pastoria would install SCR to control emissions of NO_x. Calpine completed construction of the Pastoria facility in 2005 and ultimately installed SCR technology as opposed to XONON™. To

date, XONON™ technology is not commercially available for large combustion turbines such as the Project.

Based on the fact that the XONON™ technology is not currently commercially available and has not been proven on combustion turbines of the size proposed by the Project, it is not further considered in this analysis.

SCONO_x™ – SCONO_x™ or EM_x™ is a proprietary catalytic oxidation and adsorption technology that uses a single catalyst for the control of NO_x, CO, and VOC emissions. The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes NO to NO₂, CO to CO₂, and VOC to CO₂ and water, while NO₂ is adsorbed onto the catalyst surface and chemically converted to and stored as potassium nitrates and nitrites. The SCONO_x™ potassium carbonate layer has a limited adsorption capability and requires regeneration approximately every 12-15 minutes in normal service. Each regeneration cycle requires approximately 3-5 minutes. At any point in time, approximately 20% of the 40 to 60 compartments in a SCONO_x™ system would be in regeneration mode, and the remaining 80% of the compartments would be in oxidation/adsorption mode.

Regeneration of the adsorption layer requires exposure of the catalyst to hydrogen gas. In practice, this is accomplished by reforming natural gas with high-pressure steam to produce a gas mixture consisting of methane, carbon dioxide, and hydrogen that is passed over the catalyst beds. Initial attempts by the developer of the process to create regeneration gases from natural gas and steam within the SCONO_x™ catalyst bed (internal autothermal regeneration) failed to produce consistent results; this approach was abandoned in favor of the current offering, which uses an external steam-heated reformer that partially reforms the natural gas to produce the gas mixture that is introduced into the catalyst bed. The reformation reaction continues to some extent within the catalyst bed due to the presence of steam and the temperature of the catalyst surface, but some methane and VOC from the natural gas remain.

Because the active regenerant gas is hydrogen, the regeneration process must be performed in an atmosphere of low oxygen to prevent dilution of the hydrogen. In practice, the oxygen present in the exhaust gas of combustion turbines is excluded from the catalyst bed by dividing the catalyst bed into a number of individual cells or compartments that are equipped with front and rear dampers that are closed at the beginning of each regeneration cycle. Proper regeneration of the SCONO_x™ catalyst system depends upon the proper functioning and sealing of these sets of dampers approximately 4 times per hour so that an adequate concentration of hydrogen can be maintained in each module to accomplish complete regeneration of the catalyst before the dampers are opened and the compartment is placed back in service.

Because the $\text{SCONO}_x^{\text{TM}}$ catalyst can be “poisoned” or rendered inactive by even the very small amounts of sulfur compounds present in natural gas, a SCOSO_x catalyst bed, intended to remove trace quantities of sulfur-bearing compounds from the exhaust gas stream, is installed upstream of the $\text{SCONO}_x^{\text{TM}}$ catalyst bed. Like the $\text{SCONO}_x^{\text{TM}}$ catalyst, the SCOSO_x catalyst must be regenerated. Regeneration of the two catalyst types occurs at the same time, with the same regeneration gas supply provided to both; however, the sulfur-bearing regeneration gas for the SCOSO_x catalyst exits the $\text{SCONO}_x^{\text{TM}}$ modules separately from the $\text{SCONO}_x^{\text{TM}}$ regeneration gas to avoid contaminating the $\text{SCONO}_x^{\text{TM}}$ catalyst beds. Both the regeneration gas streams are returned to the gas turbine exhaust stream downstream of the $\text{SCONO}_x^{\text{TM}}$ module.

The external reformer used to create the regeneration gases is supplied with steam and natural gas. To avoid poisoning the reformer catalyst, the natural gas supplied to the reformer passes through an activated carbon filter to remove some of the sulfur-bearing compounds that are added to natural gas to facilitate leak detection.

The regeneration cycle time is expected to be controlled using a feedback system based on NO_x emission rates. That is, the higher the NO_x emissions are relative to the design level, the shorter the absorption cycle, and regeneration cycles will occur more frequently. This is analogous to the use of feedback systems for controlling reagent (ammonia or urea) flow rates in an SCR system.

Maintenance requirements for $\text{SCONO}_x^{\text{TM}}$ systems are expected to include periodic replacement of the reformer fuel sulfur carbon unit, periodic replacement of the reformer catalyst, periodic washings of the SCOSO_x and $\text{SCONO}_x^{\text{TM}}$ catalyst beds, and periodic replacement of the catalyst beds. The replacement frequency for the reformer sulfur carbon unit and reformer catalyst is unknown at present. The SCOSO_x catalyst is expected to require washing once per year. The lead (upstream) $\text{SCONO}_x^{\text{TM}}$ catalyst bed is expected to require washing once per year, while the trailing (downstream) $\text{SCONO}_x^{\text{TM}}$ catalyst bed(s) are expected to require washing once every three years. The annual catalyst washing process is expected to take several days for large combustion turbines and produce hundreds of thousands of gallons of wastewater. The estimated catalyst life is reported to be 7 washings; the guaranteed catalyst life is three years.

Estimates of the control system efficiency vary. ABB Environmental (now ALSTOM Power) has indicated that the $\text{SCONO}_x^{\text{TM}}$ system is capable of achieving a 90% reduction in NO_x ; a 90% reduction in CO, to a level of 2 ppm; and an 80-85% reduction in VOC emissions (ABB Environmental). The VOC reduction is not likely to be achieved with low VOC inlet concentrations, in the 1-2 ppm range. Commercially quoted NO_x emission rates for the $\text{SCONO}_x^{\text{TM}}$ system range from 2.0 ppm on a 3-hour average basis, representing a 78% reduction

(ABB TMP), to a 1.0 ppm with no averaging period specified. The SCONOX[™] system does not control or reduce emissions of sulfur oxides or particulate matter from the combustion device.

The Redding Power Plant in California, a 43 MW natural gas-fired combustion turbine, was permitted with a 2.0 ppm demonstration limit using SCONOX. However, the unit could not meet the demonstration limit; consequently, the permit limit had to be revised upwards to 2.5 ppm (letter from Shasta County Department of Resource Management to Redding Electric Utility dated June 23, 2005).

To date, SCONOX[™] technology has been commercially demonstrated on natural gas and dual-fuel turbine installations presented in the following table.

Turbine & Fuel	Facility	Location	Startup Date	NO_x Permit Limit
5 MW Solar Taurus 60 dual-fuel ¹ turbine	Wyeth BioPharma cogeneration facility Unit #2	Andover, MA	September 2003	2.5 ppm (gas) 15.0 ppm (oil)
5 MW Solar Taurus 60 dual-fuel ¹ turbine	Montefiore Medical Center cogeneration Facility	Bronx, NY	June 2002	2.5 ppm (gas) 15.0 ppm (oil)
45 MW ALSTOM GTX100 gas turbine	Redding Electric municipal plant	Redding, CA	June 2002	2.0 ppm (gas)
Two 15 MW Solar Titan 130 gas turbines	University of California cogeneration facility	San Diego, CA	July 2001	2.5 ppm (gas)
5 MW Solar Taurus 60 dual-fuel turbine	Wyeth BioPharma cogeneration facility Unit #1	Andover, MA	1999	2.5 ppm (gas) 15.0 ppm (oil)
32 MW GE LM2500 gas turbine	Sunlaw Federal cogeneration facility	Vernon, CA	1996	Actual ²

¹ Dual-fuel: pipeline natural gas and low-sulfur diesel fuel oil.

² Below 2.0 ppm for nearly all of the plant's operating hours in 2000 and 2001, below 1.5 ppm performance for 97% of those operating hours, and below 1.0 ppm for over 90% of the hours.

The performance of SCR and SCONOX[™], insofar as NO_x emission levels are concerned, is essentially equivalent. Both technologies have demonstrated the ability to reduce NO_x emissions by at least 90%. The principal differences between the two technologies are

associated with whether the low emission levels proposed have been “achieved in practice,” cost-effectiveness, and secondary environmental impacts.

SCONO_x[™] technology has been found to be capable of achieving compliance with permitted NO_x levels of 2.0 and 15.0 ppm for natural gas and fuel oil operation, respectively. The presently available technical information does not support a conclusion that this technology can be proven on larger combustion turbines such as the Project.

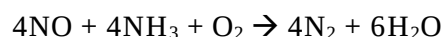
4.4.2.2 Auxiliary Boiler

The following control technologies for NO_x were evaluated: Low-NO_x Burners, Flue Gas Recirculation (FGR), SCR, and SNCR.

Low-NO_x Burners – Dry low NO_x burners reduce NO_x through staged combustion. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_x formation. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low-NO_x burners.

Flue Gas Recirculation (FGR) – In an FGR system, a portion of the flue gas is recirculated from the exhaust stream back to the burner. The recirculated gas is mixed with combustion air as an inert diluent prior to being fed to the burner. The FGR system reduces NO_x emissions because the recirculated gas reduces combustion temperatures, thus suppressing the thermal NO_x mechanism. FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. An FGR system is normally used in combination with specially designed low-NO_x burners capable of sustaining a stable flame despite the increased recirculated gas flow resulting from the use of FGR. Together, low-NO_x burners and FGR are capable of reducing NO_x emissions by 60 to 90 percent.

Selective Catalytic Reduction (SCR) – SCR technology uses ammonia as a reducing agent in the presence of oxygen over a catalyst. The general chemical reaction is:



The process includes an ammonia delivery system and a selective catalytic reaction section. Vaporized ammonia (or urea) is introduced into the flue gas stream via an injection grid located upstream of the catalyst. NO_x emission reductions of 75 to 90 percent have been achieved through the use of SCR.

The proposed auxiliary boiler for the combined cycle project will be limited to natural gas firing only and will be operated for the purposes of supplying steam for fast-startup of the plant,

including equipment piping pre-warming and startup fuel heating. Additionally, it will be used to maintain vacuum in the condenser and to provide steam seals when the combined cycle facility is shutdown, but expected to be brought back online for either a warm or hot start. SCR emission control technology is not considered technically feasible for the proposed auxiliary boiler because the design effectiveness of an SCR is not achieved until the flue gas temperature reaches between 400 and 800°F. The proposed auxiliary boiler will be required to supply steam in an expedited manner to minimize the duration of the combined cycle unit start-up, which produces elevated pollutant emission concentrations from the turbine during each start-up procedure.

4.4.2.3 Emergency Diesel Engines

U.S. EPA's Alternative Control Techniques (ACT) Document for reciprocating engines lists add-on techniques such as SCR, as well as combustion control techniques such as ignition timing retard, for NO_x control from diesel engines. The ACT concludes that add-on controls are not cost effective for small emergency diesel engines that operate less than 500 hours/year. While cost is not a factor that may be considered in LAER determinations, add-on techniques would be ineffective. Since the emergency diesel fire pump and emergency diesel generator will run for limited durations, the SCR would never reach the operating temperature required to remove any substantial NO_x emissions, and thus would provide no benefit. Therefore, add-on controls do not represent NO_x LAER for the emergency diesel engines.

4.4.2.4 Determination of LAER for NO_x

4.4.2.4.1 Combined Cycle Combustion Turbine

Keasbey Energy Center proposes DLN in combination with SCR, in order to achieve LAER for NO_x emissions from the Project's combined-cycle unit. These technologies, when considered together, represent the most stringent NO_x controls available for combined cycle combustion turbines. The proposed NO_x emission limit for the turbine during natural gas operation is 2.0 ppmvd @15% O₂, to be achieved at all operating loads between 30 and 100% of full load.

The proposed NO_x emission limit for the turbine during ULSD operation is 4.0 ppmvd @15% O₂, to be achieved at all operating loads between 50 and 100% of full load. Based upon a review of RBLC and other recent permits for ULSD fired combined cycle turbines, there are two Projects permitted less than 4.0 ppmvd @15% O₂. These projects are the Sewaren Generating Station and the Middlesex Energy Center, both of which will use GE 7HA.02 combustion turbine technology. Therefore, 4.0 ppmvd @15% O₂ is considered the most stringent limit guaranteed for a large ULSD fired H-Class combined cycle turbine.

4.4.2.4.2 Auxiliary Boiler

Based on the analysis presented above, the Project is proposing to limit the total hours of operation of the auxiliary boiler to 4,000 hrs/year and utilize ultra-low-NO_x burners, flue gas recirculation (FGR) and good combustion practices to achieve a NO_x emission rate of 0.01 lb/mmBtu as LAER for the natural gas-fired auxiliary boiler. This vendor guaranteed limit, equivalent to 9.0 ppmvd @ 3% O₂, is equal to the lowest permitted emission rate identified in Appendix C (RBLC results). For these reasons, LAER for NO_x emissions from the auxiliary boiler was selected as 0.01 lb/mmBtu.

4.4.2.4.3 Emergency Diesel Engines

Although add-on controls, such as SCR, have been employed to reduce emissions from diesel engines with greater annual operating capacity factors, the limited annual operation rules out such controls. Thus, the Project proposes limited hours of operation (100 hours per year for each), good combustion practices, and the use of ULSD as LAER to achieve a NO_x emission rate of 1.19 lb/mmBtu for the emergency diesel generator and 0.80 lb/mmBtu for the emergency diesel fire pump. For the emergency diesel generator, the limit is based on the NSPS Subpart IIII emissions standard of 6.4 g/kW-hr (NO_x + NMHC) for Tier 2 engines found in Table 1, 40 CFR 89.112. It corresponds to a NO_x permit limit of 4.63 g/hp-hr. For the emergency fire pump, the limit is based on the NSPS Subpart IIII emissions standard of 3.0 g/hp-hr (NO_x + NMHC). These two limits result in 0.85 tons of NO_x per year from the emergency generator and 0.09 tons per year from the emergency fire pump due to their limited hours of operation.

4.5 LAER Analysis for Volatile Organic Compounds

Since potential emissions from the Project exceed the 25 ton/year non-attainment NSR threshold, VOC emissions must meet LAER requirements. The combined cycle combustion turbine, auxiliary boiler, and emergency diesel engines are all sources of VOC emissions at the proposed Project. This section demonstrates that the proposed VOC emissions and controls meet the requirements of LAER. Because LAER requirements are at least as stringent as BACT or SOTA, the LAER analysis also satisfies the BACT and SOTA demonstration for VOC.

4.5.1 Review of VOC RBLC Database

4.5.1.1 Combined Cycle Combustion Turbine

The search of the RBLC and available permits identified numerous natural gas-fired combined cycle combustion turbine projects with VOC emission limits ranging from 0.7 to 4.0 ppm with the majority of the VOC emission limits in the 1.0-2.0 ppm range. The majority of these units employ an oxidation catalyst and good combustion practices to control VOC emissions.

For ULSD firing, there are far fewer recently permitted combined-cycle combustion turbine Projects. The most recently permitted combined-cycle combustion turbines firing ULSD are permitted with VOC emissions limits ranging from 2.0 ppm to 13.0 ppm. All of the projects permitted at these levels use oxidation catalyst technology.

4.5.1.2 Auxiliary Boiler

The RBLC and recent air permit search for natural gas-fired boilers between 10 and 100 mmBtu/hr in size identified VOC emission limits between 0.002 to 0.016 lb/mmBtu with a majority of boilers being permitted in the 0.003-0.005 lb/mmBtu range. More recent boiler permits are in the 0.004-0.005 lb/mmBtu range with the most stringent permit limit reported being 0.0015 lb/mmBtu.

4.5.1.3 Emergency Diesel Engines

An RBLC and recent permit search for emergency diesel generators indicated a range between 0.003 and 0.15 lb/mmBtu. The most recent permit, issued November 2014, for an emergency generator of identical size is the Moundsville Combined Cycle Power Plant in West Virginia, which was permitted for 0.09 lb/mmBtu. The most stringent VOC emission permit limit shown in the RBLC database and permit search for a diesel fire pump of similar size and use as the proposed diesel fire pump is 0.017 lb/mmBtu. The range of VOC emission limits for diesel fire pumps is 0.017 – 1.763 lb/mmBtu.

4.5.2 Identification of VOC Control Options and Technical Feasibility

4.5.2.1 Combined Cycle Combustion Turbine

Combustion turbines have inherently low VOC emissions. The emissions of VOC in a combustion process are a result of the incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO₂ and H₂O.

The only post-combustion control method practical to reduce VOC emissions from combustion turbines is an oxidation catalyst. The optimum location for VOC control, in the 900 to 1,100°F range, would be upstream of the HRSG or in the front-end section of the HRSG. However, at the high temperatures necessary to make the oxidation catalyst optimized for VOC reduction, there is the undesirable result of causing substantially more conversion of SO₂ to SO₃ which may, in turn, react with water and/or ammonia to form sulfuric acid mist and/or ammonia salt PM-10/PM-2.5 emissions. Therefore, the placement of the oxidation catalyst in the “cooler”

section of the HRSG necessary for CO control is optimal, and has the additional side benefit of reducing VOC emissions from the combustion turbine.

4.5.2.2 Auxiliary Boiler

The rate of VOC emissions from boilers depends on combustion efficiency. Fuel hydrocarbons not converted to CO₂ can result in VOC emissions due to incomplete combustion. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Although the primary hydrocarbon constituents of natural gas – methane and ethane – are not considered to be VOC, trace amounts of VOC species in the natural gas fuel may also contribute to VOC emissions if they are not completely combusted in the boiler.

No technically feasible post-combustion control methods have been identified to assure the reduction of VOC emissions from auxiliary boilers. However, it is feasible to utilize an oxidation catalyst to control CO emissions from a boiler, which may also reduce VOC emissions. As described in the CO BACT analysis, a few recently issued air permits specify oxidation catalysts for boilers.

4.5.2.3 Emergency Diesel Engines

VOC from diesel engines are composed of a variety of organic compounds emitted into the atmosphere because of incomplete combustion. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. The quench layer is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperature to be too low to support combustion. Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed. Add-on controls are not technically feasible.

4.5.3 Determination of LAER for VOC

4.5.3.1 Combined Cycle Combustion Turbine

The Project is proposing to install an oxidation catalyst designed to reduce VOC emissions when firing natural gas to 1.0 ppm without duct burning and 2.0 ppm with duct burning at normal operating loads between 30% and full load. Based upon a review of LAER and BACT

determinations in U.S. EPA's RBLC and permits for Projects not included in the RLBC, the majority of recent VOC BACT determinations include combustion controls and oxidation catalysts. The most stringent limits on Projects that are in operation are 1.0 ppm for VOC without duct firing and a range of 1.5 ppm to 3.9 ppm with duct firing.

The Projects that have VOC limits that are more stringent are: the Brunswick Power Project (0.7 ppm without duct firing) and the West Deptford Energy Station (0.7 ppm without duct firing and 1.0 ppm with duct firing). The Brunswick Power Station is currently under construction and the West Deptford Energy Station Project Expansion is not yet operating. As such, a VOC limit less than 1.0 ppm without duct firing and 2.0 ppm with duct firing is not yet considered demonstrated in practice due to lack of sufficient operating history at those levels.

The Project is proposing to install an oxidation catalyst designed to reduce VOC emissions when firing ULSD to 2.0 ppm without duct burning at normal operating loads between 50% and full load. The permitted VOC emission rate for ULSD firing of the Pioneer Valley Generating Project is 6.0 ppm and for the Kleen Energy Project is 3.6 ppm. The vendor guarantee for the GE 7HA.02 turbine firing ULSD is 2.0 ppm with the installation of an oxidation catalyst. This emission level is below the lowest permitted limits for ULSD fired combustion turbines and is equivalent to the proposed permit limit by CPV Towantic for a GE 7HA.01 turbine. AND Sewaren Generating Station for a GE 7HA.02 turbine.

4.5.3.2 Auxiliary Boiler

The auxiliary boiler is proposed to employ good combustion practices and have a restriction on annual operation of 4,000 hours per year. The Project proposes that these control methods represent VOC LAER by limiting emissions to 0.005 lb/mmBtu.

4.5.3.3 Emergency Diesel Engines

The application of good combustion practices and limited operating hours is proposed in order to achieve LAER for the emergency diesel fire pump and emergency diesel generator. The maximum VOC emissions from the emergency diesel generator and emergency fire pump are 0.15 g/hp-hr and 0.31 g/hp-hr, respectively. Potential VOC emissions from these units are less than 0.04 tons/year combined.

4.6 BACT Analysis for Carbon Monoxide

The combined cycle combustion turbine and duct burner, auxiliary boiler, emergency diesel generator, and emergency diesel fire pump are all sources of CO emissions at the proposed

Project. Since potential CO emissions from the Project exceed the PSD significant emission rate threshold, CO emissions from all the units must incorporate BACT.

4.6.1.1 Review of CO BACT Database

4.6.1.2 Combined Cycle Combustion Turbine

A review of numerous natural gas-fired combined cycle facilities listed in the U.S. EPA's RBLC as well as recently issued air permits lists CO emission limits primarily ranging from 1.5 to 4 ppm. There are only six recent projects within the RBLC that have proposed permit limits for ULSD fired combustion turbines that have CO limits. These projects have CO limits ranging from 1.8 ppm to 9 ppm.

4.6.1.3 Auxiliary Boiler

The CO limits for boilers of similar type listed in the RBLC primarily range from 0.007 to 0.083 lb/mmBtu. Most recently issued permitted limits are in the 0.017-0.037 lb/mmBtu range. A recently issued draft permit is for a 97.5 mmBtu/hr boiler at the Middlesex Energy Center, Sayreville, NJ, with a permitted limit of 0.037 lb/mmBtu.

4.6.1.4 Emergency Diesel Engines

The RBLC indicates that the CO permit limits for diesel engines similar in size to the proposed emergency diesel generator primarily range from 0.04 to 0.82 lb/mmBtu, as summarized in Appendix C. The permit limits for diesel engines similar in size to the proposed emergency diesel fire pump primarily range from 0.03 to 0.82 lb/mmBtu, as summarized in Appendix C.

4.6.2 Identification of CO Control Options and Technical Feasibility

The following sections detail the options that were identified for controlling CO emissions from the combustion turbine/duct burner, auxiliary boiler, emergency diesel generator, and emergency diesel fire pump. The technical feasibility of each option is also discussed.

4.6.2.1 Combined Cycle Combustion Turbine

The formation of CO in the exhaust of a combustion turbine is the result of incomplete combustion of fuel. Several conditions can lead to incomplete combustion, including insufficient O₂ availability, poor air/fuel mixing, cold wall flame quenching, reduced combustion temperature, and decreased combustion residence time and load reduction. By controlling the combustion process carefully, CO emissions can be minimized.

After combustion control, the only practical control method to reduce CO emissions from combustion turbines is an oxidation catalyst. Exhaust gases from the turbine are passed over a catalyst bed where excess air oxidizes the CO to CO₂. CO reduction efficiencies in the range of 80 to 90 percent can be guaranteed, although CO reduction may at times be somewhat less than the design value at the low inlet concentrations that are expected for the GE 7HA.02. No other technically feasible options are identified for combustion turbine CO control. Drawbacks of the oxidation catalyst include added cost, reduced turbine output and efficiency due to increased back pressure, and the potential for increased PM/PM-10/PM-2.5 and/or sulfuric acid mist emissions.

4.6.2.2 Auxiliary Boiler

An oxidation catalyst for the auxiliary boiler is not considered technically feasible since the auxiliary boiler is required to quickly supply steam to the combined cycle unit during the start-up procedure and the oxidation catalyst requires a high flue gas temperature to achieve effective control. A more effective method of reducing emissions, including CO, is by restricting operation on an annual basis.

4.6.2.3 Emergency Diesel Engines

As reflected by existing permits, add-on control technology is not practicable for control of CO emissions from an emergency diesel engine operating less than 100 hours per year. Good combustion control practices and limited operating hours represent CO BACT for the Project's emergency diesel fire pump and emergency diesel engine.

4.6.3 Determination of BACT for CO

4.6.3.1 Combined Cycle Combustion Turbine

The Project is proposing to install an oxidation catalyst designed to reduce CO emissions to 2.0 ppm @15% O₂ during normal operation on natural gas from 30% to full load. There have been recent permits issued (West Deptford Energy Station, Brunswick Power Station, Palmdale Hybrid Power, Avenal Energy, Warren County Power, and CPV Towantic) with lower limits than 2.0 ppm. The Brunswick and Warren Power Projects are currently under construction and the Avenal, Palmdale, West Deptford, and Towantic Projects have not yet started construction. As such, CO limits less than 2.0 ppm are not yet considered demonstrated in practice due to lack of sufficient operating history at those levels. Therefore, the 2.0 ppm limit is considered the most stringent limit achieved in practice for a large combined cycle turbine.

Additionally, although the proposed emission rate is marginally higher than a couple of recently permitted projects, the U.S. EPA's Environmental Appeals Board (EAB) decision³ on March 14, 2014 regarding the appeal of the La Paloma Energy Center, LLC PSD permit makes clear that minor differences in permitted PSD emission rates are allowable to account for different technologies, and that turbine model selection cannot be taken into account when determining BACT for a project. The proposed CO BACT emission rate during natural gas firing represents the vendor guarantee with an oxidation catalyst and is consistent with the majority of recently permitted projects.

The Project is proposing to install an oxidation catalyst designed to reduce CO emissions to 2.0 ppm @15% O₂ during normal operation on ULSD from 50% to full load. The Kleen Energy project is limited to 1.8 ppmvd at 15% O₂. The GE guaranteed CO emission rate for ULSD firing with an oxidation catalyst is 2.0 ppmvd at 15% O₂ for the 7HA.02 combustion turbine. The GE guarantee is marginally higher than the Kleen Energy CO limit, which comes at the expense of a higher VOC limit that is higher than some VOC limits in the RBLC database. Therefore, CO BACT for oil firing is proposed to be 2.0 ppmvd, which is consistent with the levels achieved by the Caithness Bellport Energy Center (now known as Caithness Long Island Energy Center, using Siemens F Class equipment), and recent guarantees by GE on other Projects with H Class combustion turbines.

4.6.3.2 Auxiliary Boiler

The Project is proposing to limit the auxiliary boiler CO emissions to a limit of 0.037 lb/mmBtu, corresponding to the anticipated guarantee level of 50 ppm, and to restrict full load operation to 4,000 hours per year to satisfy BACT requirements. The lowest CO limit identified for any auxiliary boiler at an operational combined cycle combustion turbine facility without an oxidation catalyst as summarized in Appendix C is 0.036 lb/mmBtu (Caithness Bellport Energy Center).

4.6.3.3 Emergency Diesel Engines

Existing permits show that add-on control technology is not practical for control of CO emissions from emergency equipment. Therefore, the Project is proposing BACT for CO emissions through good combustion practices and limiting operating hours. The proposed emission rate from the emergency diesel generator is 2.61 g/hp-hr. The proposed emission rate for the emergency diesel fire pump is 1.42 g/hp-hr.

³

[http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Recent~Additions/687C700F9FD042F585257C9B006369CE/\\$File/La%20Paloma.pdf](http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Recent~Additions/687C700F9FD042F585257C9B006369CE/$File/La%20Paloma.pdf)

4.7 BACT Analysis for PM/PM-10/PM-2.5

The combined cycle combustion turbine and duct burner, auxiliary boiler, emergency diesel engines, and cooling tower are all sources of PM, PM-10, and PM-2.5 emissions. Because potential emissions from the Project exceed the PSD significant emission rates for PM/PM-10/PM-2.5 emissions, PM/PM-10/PM-2.5 emissions from the aforementioned equipment must meet BACT emission rates.

4.7.1 Review of PM/PM-10/PM-2.5 BACT Databases

4.7.1.1 Combined Cycle Combustion Turbine

A review of numerous natural gas-fired combined cycle facilities from the U.S. EPA's RBLC and recently issued air permit searches (see Appendix C) lists a wide range of PM/PM-10/PM-2.5 emissions on a pound per hour, lb/mmBtu, and grains of sulfur per 100 scf of natural gas basis. The PM emission limits for combustion turbine projects are dependent on the make and model of the combustion turbine selected, the fuel sulfur content, the vendor guaranteed emission rate at full load and at part loads, and the duct burner operational status. Vendors typically will provide higher emission guarantees on a lb/mmBtu basis at part load even though emissions on a pound per hour basis are lower at part load.

A review of recently permitted combined cycle facilities from the USEPA's RBLC and recently issued air permit searches (see Appendix C) lists PM/PM-10/PM-2.5 emission limits ranging from 0.003 to 0.008 lb/mmBtu for natural gas and PM/PM-10/PM-2.5 emission limits ranging from 0.01 to 0.05 lb/mmBtu for ULSD.

4.7.1.2 Auxiliary Boiler

A review of the RBLC (see Appendix C) shows that typically good combustion practices and low-sulfur fuel have been used as BACT for gas-fired boilers. PM/PM-10/PM-2.5 emission limits for gas-fired boilers of similar size range between 0.002 and 0.008 lb/mmBtu.

4.7.1.3 Emergency Diesel Engines

A review of the RBLC (see Appendix C) shows that only good combustion, limitations on operating hours, and low-sulfur fuels have been used as BACT for emergency diesel engines. The RBLC PM/PM-10/PM-2.5 emission levels for diesel generators range primarily from 0.006 to 0.047 lb/mmBtu, as summarized in Appendix C. The RBLC PM/PM-10/PM-2.5 emission levels for emergency diesel fire pumps range primarily from 0.024 to 0.048 lb/mmBtu, as summarized in Appendix C.

4.7.1.4 Cooling Tower

A review of PM/PM-10/PM-2.5 emission limits for cooling towers presented in the RBLC establishes drift/mist eliminators as the most commonly used control technique for PM/PM-10/PM-2.5 emissions. The lowest drift/mist eliminator rate identified in the RBLC for cooling towers is 0.0005% (see Appendix C).

4.7.2 Identification of PM/PM-10/PM-2.5 Control Options and Technical Feasibility

4.7.2.1 Combined Cycle Combustion Turbine

PM, PM-10, and PM-2.5 emissions from the combustion turbine may be formed from non-combustible constituents in fuel or combustion air, from products of incomplete combustion, or from the formation of ammonium sulfates due to the conversion of SO₂ to SO₃, which is then available to react with ammonia and form ammonium sulfate or ammonium bisulfate post combustion. It is conservatively expected that all PM from the turbine will be equal to PM-10 and PM-2.5. PM, PM-10, and PM-2.5 emissions from the combustion turbine are inherently low.

The combustion of clean burning fuels is the most effective means for controlling PM emissions from combustion equipment. The Project is not aware of any natural gas-fired combustion turbine project that has been required to add on PM, PM-10, or PM-2.5 controls.

Post-combustion controls, such as baghouses, scrubbers and electrostatic precipitators (ESP) are impractical due to the high pressure drops associated with these units, the large flue gas volumes, and the low concentrations of PM/PM-10/PM-2.5 present in the exhaust gas.

4.7.2.2 Auxiliary Boiler

PM/PM-10/PM-2.5 emissions from natural gas-fired boilers may be due to products of incomplete combustion as well as non-combustible constituents in the flue gas stream. Proper burner design and operation, as well as the primary use of natural gas, will control PM/PM-10/PM-2.5 emissions to low levels. PM/PM-10/PM-2.5 control technologies, such as ESP or fabric filters, are common practice on solid fuel boilers. ESPs are also applied on boilers firing residual oil, where the filterable component of PM is greater than that for the proposed Project.

4.7.2.3 Emergency Diesel Engines

Particulate matter emissions from diesel fired internal combustion engines may result from trace metals present in the fuel, unburned carbon-containing materials, and sulfate formation. Good combustion practices and use of clean fuels are the methods currently utilized to minimize

PM/PM-10/PM-2.5 emissions from diesel engines. Post-combustion controls, such as baghouses, scrubbers, and ESPs are impractical due to the high-pressure drops associated with these technologies and the low concentrations of PM, PM-10, and PM-2.5 present in the exhaust gas. In addition, any add-on controls applied would have extremely high cost, on a dollar per ton PM/PM-10/PM-2.5 removed basis, since this emergency equipment is expected to operate infrequently. No other PM/PM-10/PM-2.5 control devices are identified for diesel engines in U.S. EPA's AP-42, Compilation of Air Pollutant Emission Factors, Section 3.

4.7.2.4 Cooling Tower

PM/PM-10/PM-2.5 emissions from cooling towers occur because wet cooling towers provide direct contact between the cooling water and the air passing through the tower. Some of the liquid water may be entrained within the air stream and be carried out of the tower as "drift" droplets. Therefore, the PM/PM-10/PM-2.5 constituent (suspended and dissolved solids) of the drift droplets may be classified as an emission. Because drift droplets contain the same chemical impurities as does the water circulating through the tower, these impurities can be converted into airborne emissions. To reduce drift from cooling towers, drift eliminators are usually incorporated into the tower design to prevent water droplets from leaving the tower and to reduce particulate emissions. The only alternative would be to reduce the solids content of the water, either by water treatment or by reducing the cycles of concentration, which would increase the blow down discharge and make-up water requirements of the tower.

4.7.3 Determination of BACT for PM/PM-10

4.7.3.1 Combined Cycle Combustion Turbine

Good combustion techniques and low-sulfur fuels have been proposed to limit PM/PM-10/PM-2.5 emissions. The proposed emission limit for PM/PM-10/PM-2.5 when firing natural gas in the combined cycle combustion turbine is 0.0068 lb/mmBtu without duct firing and 0.0070 lb/mmBtu with duct firing. During ULSD firing, the Project is proposing to limit PM/PM-10/PM-2.5 emissions to 0.0368 lb/mmBtu. These values are within the range of recent BACT determinations for combined cycle combustion turbines. It should be noted that the Pennsylvania DEP recently issued a Plan Approval Permit⁴ for the Moxie Freedom Project for GE 7HA.02 combustion turbines with very similar lb/mmBtu limits during natural gas operation (the Moxie Freedom Project is proposed with natural gas operation only).

⁴ <http://www.pabulletin.com/secure/data/vol45/45-22/1012a.html>

4.7.3.2 *Auxiliary Boiler*

The Project proposes the exclusive use of natural gas, a clean-burning and low sulfur fuel in conjunction with good combustion practices as BACT. The proposed PM/PM-10/PM-2.5 limit for the auxiliary boiler is 0.007 lb/mmBtu, which is consistent with many other recent BACT determinations for natural gas-fired boilers.

4.7.3.3 *Emergency Diesel Engines*

The Project proposes to use low sulfur fuel, employ good combustion practices, and limit operating hours as BACT for PM/PM-10/PM-2.5. For the emergency diesel generator, the proposed limit is 0.15 g/hp-hr, and is equal to the NSPS Subpart IIII emissions standard of 0.2 g/kW-hr for Tier 2 engines found in Table 1, 40 CFR 89.112, which is equivalent to 0.15 g/hp-hr. For the emergency diesel fire pump, the limit is 0.118 g/hp-hr, and is less than the NSPS Subpart IIII, emissions standard of 0.15 g/hp-hr.

4.7.3.4 *Cooling Tower*

The cooling tower for the proposed Project will be equipped with high-efficiency drift eliminators for emission control of PM/PM-10/PM-2.5 occurring as dissolved and suspended solids in the drift droplets. The proposed BACT limits for the cooling tower are a drift eliminator rate of 0.0005%, which is the lowest drift rate that will be guaranteed by cooling tower vendors and will limit the potential PM emissions to 2.39 lb/hr, the potential PM-10 emissions to 1.55 lb/hr, and the potential PM-2.5 emissions to 0.58 lb/hr. Because the proposed BACT proposal for PM/PM-10/PM-2.5 emissions from the cooling tower is consistent with the most stringent limit found in the RBLC database, no further analysis is required.

4.8 **BACT Analysis for Sulfuric Acid Mist**

H₂SO₄ emissions, in addition to being a function of fuel sulfur content, are also related to the amount of oxidation of fuel sulfur to SO₃. Sulfuric acid is produced when SO₂ is converted to SO₃ in the presence of a catalyst and is then further combined with water to form H₂SO₄ (sulfuric acid). To be available to react with water to form sulfuric acid, the SO₃ will have to avoid first reacting with ammonia slip (and forming ammonia salts). During the combustion process, most of the sulfur is converted to SO₂. For the combustion turbine, forty-five percent of the SO₂ is assumed to be converted to SO₃ as a result of the combined effects of the combustion process and oxidation of the SCR and oxidation catalysts, and eventually to H₂SO₄ and/or ammonium sulfate salts.

4.8.1 Review of H₂SO₄ BACT Database

A review of the RBLC and search of recently issued air permits indicated only one option for H₂SO₄ control. For all units where H₂SO₄ control was identified, the only option considered was the combustion of low-sulfur fuels. No other controls have been implemented on a combustion turbine, boiler, or diesel engine.

4.8.1.1 Combined Cycle Combustion Turbine

A search of numerous permits for natural gas-fired combined cycle combustion turbines yielded BACT H₂SO₄ emission limits ranging primarily between 0.0001 and 0.003 lb/mmBtu. A search of recent Projects with H₂SO₄ limits for fuel oil-fired combined cycle combustion turbines yielded a range of H₂SO₄ emission limits between 0.0012 and 0.015 lb/mmBtu.

4.8.1.2 Auxiliary Boiler

A search of the RBLC for H₂SO₄ emissions from natural gas fired boilers similar in size to the auxiliary boiler proposed at the Project shows BACT limits of 0.00009 lb/mmBtu to 0.0005 lb/mmBtu.

4.8.1.3 Emergency Diesel Engines

A search of the RBLC for H₂SO₄ emissions from emergency diesel engines yielded results ranging from 0.0002 to 0.0004 lb/mmBtu.

4.8.2 Identification of H₂SO₄ Control Options and Technical Feasibility

4.8.2.1 Combined Cycle Combustion Turbine

Strategies for the control of H₂SO₄ emissions can be divided into pre- and post-combustion categories. Pre-combustion controls entail the use of low-sulfur fuels. Post-combustion controls comprise various wet and dry flue gas desulfurization (FGD) processes. However, FGD alternatives are undesirable for use on combustion turbine power facilities due to high-pressure drops across the device, and would be particularly impractical for the large flue gas volumes and low sulfur concentrations in this situation. The use of natural gas or ULSD results in low emission levels of H₂SO₄.

4.8.2.2 Auxiliary Boiler

FGD is a technology used to control sulfur emissions from various combustion sources. Installation of such systems is an established technology principally on coal-fired and high-

sulfur oil-fired steam electric generating stations, but is not feasible for boilers fired with natural gas, such as the one proposed for this Project.

4.8.2.3 Emergency Diesel Engines

The only practical control technique available for emergency diesel engines that will operate no more than 100 hours per year is the use of low-sulfur fuel.

4.8.3 Determination of BACT for H_2SO_4

4.8.3.1 Combined Cycle Combustion Turbine

The most stringent level of control for H_2SO_4 emissions is the firing of natural gas. The Project proposes to use natural gas as the primary fuel along with ULSD as a backup fuel with limited hours of operation to meet BACT for H_2SO_4 . The sulfur content of the natural gas of 0.63 grains/100 scf was used as the design basis but does not necessarily represent the maximum sulfur content anticipated for the natural gas. CPV has no control over the sulfur content of the natural gas supplied to the facility. ULSD will have a sulfur content less than or equal to 0.0015%, by weight, which is nearly equivalent to the sulfur content proposed for natural gas.

4.8.3.2 Auxiliary Boiler

The Project proposes to fire low sulfur fuels (0.63 grains S/100 scf of natural gas as the design basis) in the auxiliary boiler to meet BACT for sulfuric acid. This proposal is consistent with the lowest limits identified in the RBLC for auxiliary boilers located at large combined cycle power plants.

4.8.3.3 Diesel Internal Combustion Engines

The Project proposes to utilize ULSD with a maximum sulfur content of 0.0015% by weight in the emergency diesel engines to meet BACT for H_2SO_4 . The selection of this fuel represents the greatest level of H_2SO_4 reduction and represents the top level of control.

4.9 BACT Analysis for Greenhouse Gas (GHG) Emissions

The sources of GHG emissions for the Project are the combined cycle combustion turbine, the auxiliary boiler, the emergency diesel engine, the emergency diesel fire pump, and electrical equipment insulated with SF_6 .

4.9.1 Review of GHG BACT Database

4.9.1.1 Combined Cycle Combustion Turbine

A summary of recent GHG BACT determinations for combined cycle power plants obtained from the RBLC and from review of other permits not in the RBLC is provided in Appendix C. Direct comparison of BACT limits is complicated by inconsistencies in the bases used to establish GHG BACT limits. For example, some heat rate (Btu/KW-hr) and output based limits (lb CO₂/MW-hr) are provided on a gross basis (i.e., the full electric output of the equipment without consideration of internal plant loads such as pumps and fans) and others are provided on a net basis (i.e., the amount of energy actually sold to the grid). Furthermore, design performance and degradation factors that are used to adjust the base heat rates based upon vendor design data to realistic long term limits vary from permit to permit.

The most recent heat rate BACT limits during natural gas operation at large combined cycle power plants range from 7,247 to 7,750 Btu/KW-hr. The most recent output based limits range from 774 to 1,000 lb CO₂/MW-hr. There is a single dual fuel large combined cycle combustion turbine BACT determination that includes a 1,000 lb CO₂/MW-hr limit (i.e., the Troutdale Energy Center). The CPV Shore facility was issued its permit at 925 lb CO₂/MW-hr, while Sewaren Generating Station (final permit) and Middlesex Energy Center (draft permit) both have been permitted at 888 lb CO₂/MW-hr.

4.9.1.2 Auxiliary Boiler

The GHG BACT limits in the RLBC and those listed in a review of proposed permits for auxiliary boilers at combined cycle combustion turbine facilities are based upon an annual ton per year limit, with the exception of the Troutdale Energy Center that is based upon a lb CO₂/mmbtu limit. Appendix C provides the annual limits. However, note that annual limits reflect the particular boiler size and gas throughput limits and will vary substantially from project to project based upon the intended purpose of the boiler.

4.9.1.3 Diesel Internal Combustion Engines

A review of the RBLC database indicates that recent permits for emergency diesel generators of the size proposed for this Project are 526 g/hp-hr and 163 lb/mmbtu. There are many permit limits based upon an annual tons per year limit that are determined per the anticipated maximum annual operation and size of the engine. The limits for emergency diesel fire pumps are similar to those for emergency diesel engines.

4.9.1.4 Electrical Equipment Insulated with SF₆

A search of the RBLC for “carbon dioxide” did not yield any results for electrical equipment insulated with SF₆ (circuit breakers).

4.9.2 Identification of GHG Control Options and Technical Feasibility

4.9.2.1 Combined Cycle Combustion Turbine

The following potentially applicable control technologies for GHG were evaluated:

CO₂ Capture and Storage – Capture and compression, transport, and geologic storage of the CO₂ is a post-combustion technology that is not considered commercially viable at this time for combined cycle power plants. However, based on requests for other GHG permit applications, carbon capture and sequestration (CCS) is evaluated further in this analysis. CCS systems involve the use of adsorption or absorption processes to remove CO₂ from flue gas, with subsequent desorption to produce a concentrated CO₂ stream. The concentrated CO₂ is then compressed to supercritical temperature and pressure, a state in which CO₂ exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO₂ would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery.

With regard to CCS, as identified by U.S. EPA, CCS is composed of three main components: CO₂ capture and/or compression, transport, and storage. 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 CO₂ 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).

Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

CO₂ Capture and Compression - Though amine absorption technology for CO₂ capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is more difficult to apply to power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO₂ concentrations. The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems:

“Current technologies could be used to capture CO₂ from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO₂ capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.”⁵

In its CCS research program plans, the DOE-NETL confirms that commercial CO₂ capture technology for large-scale power plants is not yet available and suggests that it may not be available until at least 2020:

“The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:

- (1) Develop technologies that can separate, capture, transport, and store CO₂ using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;
- (2) Develop technologies that will support industries' ability to predict CO₂ storage capacity in geologic formations to within ± 30 percent by 2015;
- (3) Develop technologies to demonstrate that 99 percent of injected CO₂ remains in the injection zones by 2015;
- (4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades.”⁶

⁵Report of the Interagency Task Force on Carbon Capture and Storage at 50 (Aug. 2010).

⁶ DOE-NETL, *Carbon Sequestration Program: Technical Program Plan*, at 10 (Feb. 2011).

Another challenge of CO₂ capture is conservation of water resources. Adding CO₂ separation facilities and compression equipment significantly increases the cooling water requirements of a generating station. Studies have indicated that a natural gas fired combined cycle facility with CCS may have an increased water consumption of nearly double that of a similar facility without CCS.

CO₂ Transport and Storage - Even if it is assumed that CO₂ capture and compression could feasibly be achieved for the proposed Project, the high-volume CO₂ stream generated would need to be transported to a facility capable of storing it by an existing pipeline. The nearest CO₂ pipelines to the Project are in northern Michigan and southern Mississippi.

CO₂ Storage - Even if it is assumed that CO₂ capture and compression could feasibly be achieved for the proposed Project and that the CO₂ could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable sequestration site. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO₂ trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO₂ into the formations. Potential environmental impacts resulting from CO₂ injection that still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO₂ into brine;
- Risks of brine displacement resulting from large-scale CO₂ injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water;
- Risks to fresh water as a result of leakage of CO₂, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water; and,
- Potential effects on wildlife.

It should be noted that, based on the suitability factors described above, currently the suitability of the Newark Basin to store a substantial portion of the large volume of CO₂ generated by a facility comparable in size to the proposed Project has yet to be fully demonstrated. As concluded in the 2010 Report of the Interagency Task Force on Carbon Capture and Storage that while there is currently estimated to be a large volume of potential storage sites, “to enable widespread, safe, and effective CCS, CO₂ storage should continue to be field-demonstrated for a variety of geologic reservoir classes” and that “scale-up from a limited number of demonstration projects to wide scale commercial deployment may necessitate the consideration of basin-scale factors (e.g., brine displacement, overlap of pressure fronts, spatial variation in depositional environments, etc.)”.

Based on the abovementioned U.S. EPA guidance regarding technical feasibility and the conclusions of the Interagency Task Force for the CO₂ capture component alone (let alone a detailed evaluation of the technical feasibility of right-of-ways to build a pipeline or storage sites), CCS has been determined to not be technically feasible. Thus, CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis.

Electrical Generation Efficiency – Other than capture and sequestration of GHG emitted by combustion, the only known option for reducing GHG emissions is through maximization of the energy released during the combustion process and then through the maximization of the use or capture of that energy. To minimize GHG emissions, it is desirable to use less fuel to generate a given amount of electrical energy. There are several factors that may be examined that affect the amount of GHG produced per MW-hour of energy produced. The following energy efficiency practices were considered for the Project:

Use of Low Carbon Fuel – The first aspect to evaluate with regard to an energy efficient process is the source of fuel. 40 CFR Part 98 provides emission factors for GHG from the combustion of various fuels. Natural gas is listed as the third cleanest fuel with respect to CO₂ emissions, the third cleanest fuel with respect to CH₄ emissions, and the cleanest fuel with respect to N₂O emissions. The two cleaner fuels with respect to CO₂ emissions (coke oven gas and biogas) are not feasible sources of fuel for the Project. Therefore, with regard to fuels that can be utilized by the Project, natural gas produces the lowest GHG emissions profile. The proposed combustion turbine unit will primarily burn natural gas.

Turbine Design/Selection – In a combined cycle configuration, a HRSG is used to recover what would otherwise be waste heat lost to the atmosphere in the hot turbine exhaust. Use of heat recovery from the turbine exhaust to produce steam to power a steam turbine which generates additional electric power is the single most effective means of increasing the efficiency of combustion turbines used for electric power generation. In applications where process heat is needed, the steam produced in the HRSG can also be used to provide heat to plant processes in addition to or instead of being used to produce additional electricity. This “cogeneration” technology is not applicable to electric power generation unless there is a co-located steam host or other means of using additional recoverable waste heat.

The driving factor in the evaluation of energy efficiency is the core efficiency of the selected combustion turbine. However, in the EAB’s recent decision in the La Paloma Energy Center case, it was concluded that “combined cycle combustion turbines with efficient turbine design is the most energy efficient way to generate electricity” and that minor differences in efficiency and

GHG emission rates between different combustion turbine models are acceptable. The Project is proposing to install a single “H” Class turbine in combined-cycle configuration, which are the most efficient class of combustion turbines commercially available. The combined cycle heat rate of the proposed unit compares very favorably to the heat rate limits included in recent permits for other comparable combined cycle units which are summarized in Appendix C.

Periodic Maintenance and Tune-up – Periodic tune-up of the turbine helps to maintain optimal thermal efficiency. After several months of continuous operation of the combustion turbine, fouling and degradation results in a loss of thermal efficiency. A periodic maintenance program consisting of inspection of key equipment components and tune up of the combustor will restore performance to near original conditions. The facility will implement an extensive inspection and maintenance program.

Instrumentation and Controls – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions. Today’s H Class turbines, like the one being proposed for this Project, come from the manufacturer with a digital control package included. These systems control turbine operation, including fuel and air flow, to optimize combustion for control of criteria pollutant emissions (NO_x and CO) in addition to maintaining high operating efficiency to minimize fuel usage over the full range of operating conditions and loads.

4.9.2.2 Auxiliary Boiler

The only feasible option for reducing GHG emissions from the auxiliary boiler is to use natural gas and to limit the hours of annual operation, both of which are proposed in this PSD permit application. Natural gas has the lowest pollutant emissions amongst feasible fuels.

4.9.2.3 Emergency Diesel Engines

The emergency engines provide electricity and/or fire protection during a loss of power or fire at the facility. In accordance with National Fire Protection Agency (NFPA) requirements under NFPA-20 (Standard for the Installation of Stationary Pumps for Fire Protection), emergency fire pump engines must be either diesel or electric engines and cannot be spark-ignited engines (i.e., natural gas, propane or gasoline). Furthermore, NFPA-20 emergency fire pump engines must have a dedicated diesel fuel tank. Spark ignition engines are not suitable for fire protection due to their unreliability as compared to diesel engines.

Similar to fire pump engines, a diesel generator is required for reliability and safety purposes during an emergency. Unlike a diesel engine, an electric engine cannot be used as an emergency generator as that equipment, by design, operates only when electricity is available.

Like the other project sources, CCS could theoretically capture and store CO₂ emissions from the emergency engines. However, based upon the technical deficiencies of the current CCS technology and the lack of suitable sequestration facilities near the Project, CCS was eliminated as a BACT option for GHG control. Since spark ignition engines were eliminated as technically feasible, diesel engines are the lowest emitting technology available. Thus, the only feasible option for reducing GHG emissions from the emergency diesel engines is to limit annual operation of the units.

4.9.2.4 *Electrical Equipment Insulated with SF₆*

State-of-the-art enclosed-pressure SF₆ technology with leak detection is the primary technology used to limit fugitive emissions. In comparison to older SF₆ circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF₆ emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF₆ (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF₆ has escaped, so that it can be addressed proactively to prevent further release of the gas.

A second alternative considered in this analysis is to substitute another, non-GHG substance for SF₆ as the dielectric material in the breakers. Potential alternatives to SF₆ were addressed in the National Institute of Standards and Technology (NIST) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF₆*.⁷ According to the NIST Technical Note 1425, SF₆ is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance during many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF₆-insulated equipment. The report concluded that although "...various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture... it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore, there are currently no technically feasible options besides use of SF₆.

⁷ Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF₆*, NIST Technical Note 1425, Nov.1997.

4.9.3 Determination of BACT for GHG

4.9.3.1 Combined Cycle Combustion Turbine

BACT for GHG emissions has been determined to be the application of advanced combined-cycle technology with natural gas firing as the primary fuel with USLD firing limited to certain operating periods. In accordance with BACT requirements, BACT must be established as a federally enforceable emission rate. The recently permitted GHG emission rates in Appendix C take into account degradation in turbine performance over the expected lifetime of each project. The majority of the GHG BACT decisions in Appendix C apply several degradation factors initially established by the Bay Area Air Quality Management District for the permitting of the Russell City Energy Center. These degradation factors have been approved in numerous recent PSD permits issued by U.S. EPA and other PSD-delegated agencies. As these degradation factors have been approved by U.S. EPA, they are proposed to be applied for the Project to establish the GHG BACT emission rate. The following is a discussion of these factors and the proposed GHG BACT emission rate:

- The first factor accounts for design margin to reflect the likelihood that the equipment as constructed and installed may not fully achieve the optimal vendor specified design performance. A design margin of 3.3 percent is taken into account for this purpose.
- The second factor accounts for performance margin to reflect normal wear and tear of the combustion turbine over its useful life. A performance margin of 6.0 percent is taken into account for this purpose.
- The third factor accounts for degradation of auxiliary plant equipment (i.e., HRSG, steam turbine, ancillary pumps and motors, etc.) to reflect normal wear and tear. An auxiliary equipment degradation margin of 3.0 percent is taken into account for this purpose.

These three factors are expected to compound upon each preceding factor such that the overall degradation in plant performance is estimated to be 12.8 percent over the useful life of the combustion turbine.

Several of the projects identified in Appendix C have been permitted with a heat rate limit. Most of these limits have been established solely for a natural gas-fired operating condition, without duct firing, at ISO conditions. The proposed GE 7HA.02 CTG has a new and clean designed heat rate (in combined cycle mode) for the Project of 6,453 Btu/KW-hr HHV on a gross-output basis when firing natural gas at ISO conditions without duct firing. Applying the 12.8 percent performance degradation and margin factor discussed above, yields a gross heat rate of 7,279 Btu/KW-hr when firing natural gas at ISO conditions without duct firing. This gross heat rate is amongst the lowest heat rates identified for recent combined cycle combustion Projects and is

proposed as GHG BACT for the Project. Note that the heat rate limits for three recent Projects proposed with GE 7HA.02 combustion turbines are 7,047 Btu/KW-hr (Gross, HHV), 7,368 Btu/KW-hr (Gross, HHV) and, 6,901 Btu/KW-hr (Gross, HHV) for the Colorado Bend II, Moxie Freedom, and Middlesex Energy Center projects, respectively. Thus, the Project design has been optimized such that it will perform more in-line with recent Projects proposed with identical combustion turbines.

The Project proposes as BACT, the following energy efficiency processes, practices, and designs for the proposed combustion turbine:

- Use of combined cycle power generation technology
- Use of natural gas as the primary fuel
- Efficient turbine design
- Periodic maintenance and tune up
- Instrumentation and controls

The Project is proposing the following GHG BACT limits:

- Heat rate of 7,279 Btu/KW-hr Gross (HHV) at ISO conditions during natural gas operation and at baseload without duct firing; and
- Total annual GHG emissions for the combined cycle combustion turbine including duct firing, backup ULSD operation, and operation at part loads, will be limited to 2,357,558 tons CO_{2e} per year

The proposed heat rate above is corrected to ISO conditions of:

- Ambient Dry Bulb Temperature: 59°F
- Ambient Relative Humidity: 60%
- Barometric Pressure: 14.7 psia
- Fuel (natural gas) Higher Heating Value: 22,888 Btu/lb

The facility will utilize 40 CFR Part 75 monitoring methodology along with 40 CFR Part 98 emission factors for CH₄ and N₂O to determine compliance. Compliance with the heat rate limit at base load on natural gas without duct firing will be based on an initial performance test.

Compliance with the annual tons/year limit will be based on a rolling monthly total.

Note that the Project also will comply with the U.S. EPA's recently promulgated NSPS TTTT that will limit CO₂ emissions from new natural gas base load combustion turbines to 1,000 pounds CO₂/MW-hr-g of electricity generated on a gross basis (12-month rolling average). Based upon this U.S. EPA rule, a GHG emissions performance standard of 1,000 lb CO_{2e} per gross MW-hr is intended to reflect degradation of the equipment over time and the emissions associated with turndowns, startup, and shutdown.

Therefore, taking into account the efficiency metric for the combined-cycle power plant of pounds of CO₂ per gross MW-hr of electrical generation, the capability of HRSG duct firing, the inherent degradation in turbine performance over the life of the Facility, and the inclusion of startup and shutdowns over the course of a year of operation, it has been concluded that the Facility will meet the NSPS TTTT limit on a 365-day rolling average during facility operation. Note that during natural gas fired operation at part load, the emissions on a lb CO₂ per MW-hr basis typically range from 880 to 1,029. Thus, the 1,000 lb/MW-hr NSPS is consistent with the lifetime annual operation of the Facility that includes degradation of the equipment over time and the emissions associated with turndowns, startup, shutdown, and part load operation that are incorporated into this annual limit. It should be noted that the Pennsylvania DEP recently issued a Plan Approval Permit⁸ for the Moxie Freedom Project with a lb CO₂ per MW-hr limit of 1,000, which is consistent with the NSPS. The Moxie Freedom Project also includes two (2) GE 7HA.02 combined cycle combustion turbines in 1x1 configurations, which is a similar recent combined cycle project as compared to Keasbey Energy Center.

4.9.3.2 Auxiliary Boiler

The Project proposes to burn natural gas as the fuel and limit total operation to 4,000 hours per year. Total annual CO_{2e} emissions from the auxiliary boiler will be limited to 16,920 tons/year.

4.9.3.3 Diesel Internal Combustion Engines

The Project proposes to limit the total operating hours for the emergency diesel generator and fire pump to 100 hours per year each. Total annual CO_{2e} emissions from the emergency diesel generator and emergency diesel fire pump will be limited to 118.6 and 18.6 tons/year, respectively.

4.9.3.4 Electrical Equipment Insulated with SF₆

The Project proposes to use circuit breakers with totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout. The lockout will prevent operation of the breaker if insufficient SF₆ remains in the system.

4.10 SOTA Analysis for Ammonia

Ammonia (NH₃) emissions from the proposed combined cycle unit result from the use of SCR for NO_x control. The Project has assumed a maximum ammonia slip from the SCR system of 5 ppm. This proposed emission limit is equal to the value identified in NJDEP's most recent

⁸ <http://www.pabulletin.com/secure/data/vol45/45-22/1012a.html>

SOTA Technical Manual for combustion turbines. Therefore, the SOTA proposal for ammonia emissions is a 5 ppm emission limit.

4.11 SOTA Analysis for Opacity

Opacity is defined as the property of a substance which renders it partially or wholly obstructive to the transmission of visible light expressed as the percentage to which the light is obstructed. Particulates in large concentrations can decrease visibility by scattering and absorbing light. The opacity resulting from the operation of a natural gas fired combustion turbine is inherently low due to the low particulate emission rate.

The Project has assumed a maximum stack opacity of 10% during normal operations of the combustion turbine. The opacity may rise to as high as 20% during start-up and shutdown. Therefore, the Project is proposing to meet the NJDEP SOTA limits for opacity of 10% during normal operations on natural gas and 20% during start-up and shutdown and on ULSD firing (exclusive of visible condensed water vapor, for a period of no more than 10 seconds) as presented in the SOTA manual.

4.12 Summary of Control Technology Proposals

Tables 4–1 through 4-4 provide a summary of the control technology proposals for the Project for listed regulated pollutants.

Table 4-1: Summary of Proposed Emissions – Combined Cycle Combustion Turbine

Pollutant	Section	LAER/BACT/SOTA	Method	Basis
NO _x	4.4	2.0 ppm (NG with and without DB) 4.0 ppm (ULSD)	SCR and Dry LNB	LAER
VOC	4.5	1.0 ppm (NG without DB) 2.0 ppm (NG with DB) 2.0 ppm (ULSD)	Oxidation catalyst & good combustion practices	LAER
CO	4.6	2.0 ppm (NG with and without DB) 2.0 ppm (ULSD)	Oxidation catalyst & good combustion practices	BACT
PM/PM-10/PM-2.5	4.7	0.0070 lb/mmBtu (NG with DB) 0.0068 lb/mmBtu (NG without DB) 0.0338 lb/mmBtu (ULSD)	Low-sulfur fuels	BACT
SO ₂	3.1.2	NG composition with 0.63 grains S per 100 scf ⁽²⁾ ULSD with 15 ppm S	Low-sulfur fuels	NSPS (KKKK)
H ₂ SO ₄	4.8	NG composition with 0.63 grains S per 100 scf ⁽²⁾ ULSD with 15 ppm S	Low-sulfur fuels	BACT
CO ₂ e	4.9	7,279 Btu/KW-hr Gross (HHV) ⁽¹⁾ 2,357,558 tons CO ₂ e per year	Clean fuel and thermal efficiency	BACT
NH ₃	4.10	5 ppm	N/A	SOTA

(1) At ISO conditions during natural gas operation at baseload without duct firing.

(2) Design basis sulfur content

Table 4-2: Summary of Proposed Emissions – Auxiliary Boiler

Pollutant	Section	LAER/BACT/SOTA	Method	Basis
NO _x	4.4	0.01 lb/mmBtu	Low NO _x Burners	LAER
VOC	4.5	0.005 lb/mmBtu	Good combustion controls	LAER
CO	4.6	0.037 lb/mmBtu	Good combustion controls	BACT
PM/ PM-10/ PM-2.5	4.7	0.007 lb/mmBtu	Low sulfur fuel	BACT
H ₂ SO ₄	4.8	NG composition with 0.63 grains S per 100 scf ⁽¹⁾	Low sulfur fuel	BACT
CO ₂ e	4.9	16,920 tons CO ₂ e per year	Good combustion practices and limited operation	BACT

(1) Design basis sulfur content

Table 4-3: Summary of Proposed Emissions – Emergency Diesel Engines

Pollutant	Section	Emergency Diesel Fire Pump	Emergency Diesel Generator	Method	Basis
NO _x	4.4	2.69 g/bhp-hr	4.63 g/bhp-hr	Good combustion controls	LAER
VOC	4.5	0.31 g/bhp-hr	0.15 g/bhp-hr	Good combustion controls	LAER
CO	4.6	1.42 g/bhp-hr	2.61 g/bhp-hr	Good combustion controls	BACT
PM/ PM-10/ PM-2.5	4.7	0.12 g/bhp-hr	0.15 g/bhp-hr	Low sulfur fuels	BACT
H ₂ SO ₄	4.8	ULSD with 15 ppm S	ULSD with 15 ppm S	Low sulfur fuels	BACT
CO ₂ e	4.9	18.6 tons CO ₂ e per year	118.6 tons CO ₂ e per year	Limited Operation	BACT

Note: Sum of NO_x + NMHC (VOC) = 4.78 g/bhp-hr per NSPS IIII for EDG.
Sum of NO_x + NMHC (VOC) = 3.00 g/bhp-hr per NSPS IIII for EDFP

Table 4-4: Summary of Proposed Emissions – Cooling Tower

Pollutant	Section	BACT	Method	Basis
PM/PM-10/ PM-2.5	4.7	0.0005% drift	High efficiency drift Eliminators	BACT