Newark Energy Center Project

Newark, Essex County, New Jersey

Application for Prevention of Significant Deterioration and New Source Review Preconstruction Permit

Submitted by:

Hess Newark Energy Center, LLC

ARCADIS

Two Executive Drive
Suite 303
Chelmsford, MA 01824

October 2011

Appendices

List of Figures

List of Tables

List of Acronyms and Abbreviations

°F	degrees Fahrenheit
µg/m^3	micrograms per cubic meter
%	percent
AP-42	*Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources*
AQRV	Air Quality Related Values
BACT	Best Available Control Technology
Btu	British thermal units
CAIR	Clean Air Interstate Rule
CARB	California Air Resource Board
CATEF	California Air Toxics Emission Factor
CEMS	continuous emissions monitoring systems
CFR	Code of Federal Regulations
CI	compression ignition
CO	carbon monoxide
COC	Community of Concern
CO_2	carbon dioxide
CTG	combustion turbine generator
DB	duct burner
DLN	dry low NO_x
EJ	environmental justice
FGD	flue gas desulfurization
FLM	Federal Land Manager
g/hp-hr	grams per horsepower-hour
g/kW-hr	grams per kilowatt-hour
HAP	hazardous air pollutant
HHV	higher heating value
hp	Horsepower

HRSG	heat recovery steam generator
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid mist
ISO	International Organization for Standards
km	Kilometer
kV	Kilovolts
kW	Kilowatts
LAER	Lowest Achievable Emission Rate
lb	Pounds
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
lb/MW-hr	pounds per megawatt-hour
m	Meters
m/s	meters per second
msl	above mean sea level
MMBtu/hr	million British thermal units per hour
MW	Megawatts
n/a	not applicable
NAAQS	National Ambient Air Quality Standards
NEC	Hess Newark Energy Center, LLC
NESHAP	National Emission Standards for Hazardous Air Pollutants
ng/J	nanograms per Joule
NH_3	Ammonia
NJAAQS	New Jersey Ambient Air Quality Standards
NJDEP	New Jersey Department of Environmental Protection
NNSR	Nonattainment New Source Review
NO	nitrogen oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NPS	National Park Service

NSPS	New Source Performance Standards
O_2	Oxygen
Pb	Lead
PM_{10}	particulate matter with a diameter equal to or less than 10 microns
$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
ppm	parts per million
ppm_v	parts per million by volume
ppm_w	parts per million by weight
PSD	Prevention of Significant Deterioration
psia	pound per square inch absolute
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RGGI	Regional Greenhouse Gas Initiative
SCF	standard cubic feet
SCR	selective catalytic reduction
SIL	Significant Impact Level
SIP	State Implementation Plan
SMC	Significant Monitoring Concentration
SO_2	sulfur dioxide
SO_3	sulfur trioxide
STG	steam turbine generator
tpy	tons per year
TSP	total suspended particulates
ULSD	ultra low sulfur diesel
USEPA	United States Environmental Protection Agency
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
VCAPCD	Ventura County Air Pollution Control District
VOC	volatile organic compounds

1. INTRODUCTION

1.1 Project Overview

Hess Newark Energy Center, LLC (NEC) is proposing to construct the Newark Energy Center, a nominal 655 megawatt (MW) combined cycle electric generating facility (the project), firing natural gas as the combustion turbines' sole fuel. The major equipment will include two (2) "F" class combustion turbine generators (CTGs), two (2) supplementary-fired heat recovery steam generators (HRSGs), one (1) steam turbine generator (STG), a mechanical draft wet cooling tower, associated auxiliary and balance of plant equipment and systems. The project is intended to operate as a base load facility and is proposing to be available to operate up to 8,760 hours per year, incorporating a range of load conditions.

NEC proposes to construct the project within an approximately 25-acre portion of a property owned by Hess Corporation (Hess) at 1111 Delancy Street, near the intersection of Doremus Avenue and Delancy Street in the City of Newark, Essex County, New Jersey (the site). The site is zoned "I3" in an industrialized section of the City of Newark referred to as the "Third Industrial District" and is currently in use as a container storage facility.

Air emissions from the proposed facility primarily consist of products of combustion from the combustion turbines, HRSG duct burners, and ancillary equipment. Pollutants that are regulated under federal and New Jersey programs such as Non-attainment New Source Review (NNSR) and Prevention of Significant Deterioration (PSD) include carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), total suspended particulate (TSP), particulate matter with a diameter equal to or less than 10 microns (PM_{10}), particulate matter with a diameter equal to or less than 2.5 microns ($PM_{2.5}$), volatile organic compounds (VOC), lead (Pb), sulfuric acid mist (H_2SO_4), and air toxics. Potential emissions from the proposed project are presented in Table 1-1.

1.2 Regulatory Overview

The project will include state-of-the-art (SOTA) emissions control technology that will reflect Lowest Achievable Emissions Rate (LAER) and Best Available Control Technology (BACT), as applicable. In addition to the use of clean-burning natural gas, emissions of nitrogen oxides (NO_x) will be controlled with selective catalytic reduction (SCR). Emissions of CO and VOC will be controlled with oxidation catalyst systems.

Table 1-1: Summary of Proposed Potential Emissions and Applicable Regulatory Thresholds

Pollutant	Annual Emissions (tpy)	NNSR/PSD Major Source Threshold (tpy)[a]	PSD Significant Emission Rate (tpy)	NNSR/PSD/SOTA Applies?
NO_x	143.6	25	40 [b]	NNSR/PSD/SOTA
VOC	35.8	25	40	NNSR/SOTA
CO	486.3	100	100	PSD/SOTA
PM_{10}	96.1	100	15	PSD/SOTA
$PM_{2.5}$	93.1	100	10	SOTA
SO_2	6.2	100	40	SOTA
H_2SO_4	3.3	100	7	--
GHGs[c]	2,063,492	n/a	75,000	PSD
Pb	0.00001	10	0.6	--

a. For non-attainment pollutants, this is the non-attainment new source review major source threshold. For other pollutants, the PSD threshold is provided.

b. PSD significant emission rate for nitrogen dioxide (NO_2).

c. GHGs are expressed as CO_2 equivalents (CO_2e)

1.3 Application Overview

1.3.1 Application Organization

This permit application is divided into five sections. Section 2 provides a detailed description of the proposed project, including a facility description and estimated emissions. Section 3 provides a review of applicable regulations for the proposed project. Section 4 provides the SOTA/BACT/LAER control technology evaluations. Section 5 provides an environmental justice burden analysis. Section 6 provides a list of references. The air quality modeling analysis for the project will be provided in a separate report, the NEC Dispersion Modeling Report.

A printout of the information submitted via the Remote Aims Data Input User System (RADIUS) is included as Appendix A. Emission calculation spreadsheets providing supporting calculations for the application are provided in Appendix B.

1.3.2 Application Contacts

To facilitate NJDEP review of this application, individuals familiar with the project and this application are identified below.

Peter Haid
Hess NEC, LLC
One Hess Plaza
Woodbridge, NJ 07095
Phone: 732-750-7088
Email: phaid@hess.com

Frederick Sellars
ARCADIS
Two Executive Drive, Suite 303
Chelmsford, MA 01824
Phone: 978-937-9999 ext. 317
e-mail: frederick.sellars@arcadis-us.com

2. PROJECT DESCRIPTION

2.1 Overview

NEC proposes development of a nominal 655 MW electric generating facility at an industrial site in Newark, New Jersey. Figure 2-1 presents the proposed project location on a topographic map. The facility will be comprised of the following major and ancillary equipment:

- Two (2) “F” class CTGs;
- Two (2) HRSGs with supplemental duct firing;
- One (1) STG;
- One (1) 12-cell mechanical draft wet cooling tower;
- One (1) 1,500 kilowatt (kW) emergency diesel generator;
- One (1) natural gas-fired, 50,000 pound per hour steam production auxiliary boiler;
- One (1) 270-horsepower (hp) fire pump;
- Two (2) 19 percent aqueous ammonia storage tanks [20,000 - gallons each];
- One (1) demineralized water storage tank;
- One (1) raw water storage tank; and
- One (1) treated water storage tank
- One (1) waste water storage tank
- An associated electrical switchyard.

The project will be fueled by clean-burning natural gas to be provided by a new natural gas pipeline lateral connection from an existing Transco high pressure natural gas pipeline located approximately 1 mile west of the project site. A new natural gas metering station will be constructed on the project site. The electricity generated by the project will be transmitted by an electric cable that will extend from the project site to an interconnection point at the Public Service Enterprise Group (PSEG) Essex Substation located approximately 2.25 miles north of the project site.

The project will be capable of generating and exporting a net 655 MW of electricity to the regional electric transmission grid. The project will enter into an Interconnection

Agreement with the regional transmission operator, PJM, for the transmission of electricity to the regional power grid. The project will provide needed reliable electricity to the load-constrained electric markets in the mid-Atlantic region.

Steam condenser cooling will utilize a 12-cell mechanical draft wet cooling tower system with average consumptive water use of 2.5 million gallons per day (MGD), and a maximum of 5.4 MGD during peak summer temperatures. Water for process use will be obtained in the form of treated effluent from the Passaic Valley Sewerage Commissioners (PVSC) treatment plant located just north of the site. Project discharge wastewater, primarily cooling tower and HRSG blowdown, will be returned back to the PVSC treatment plant.

2.2 Site Location

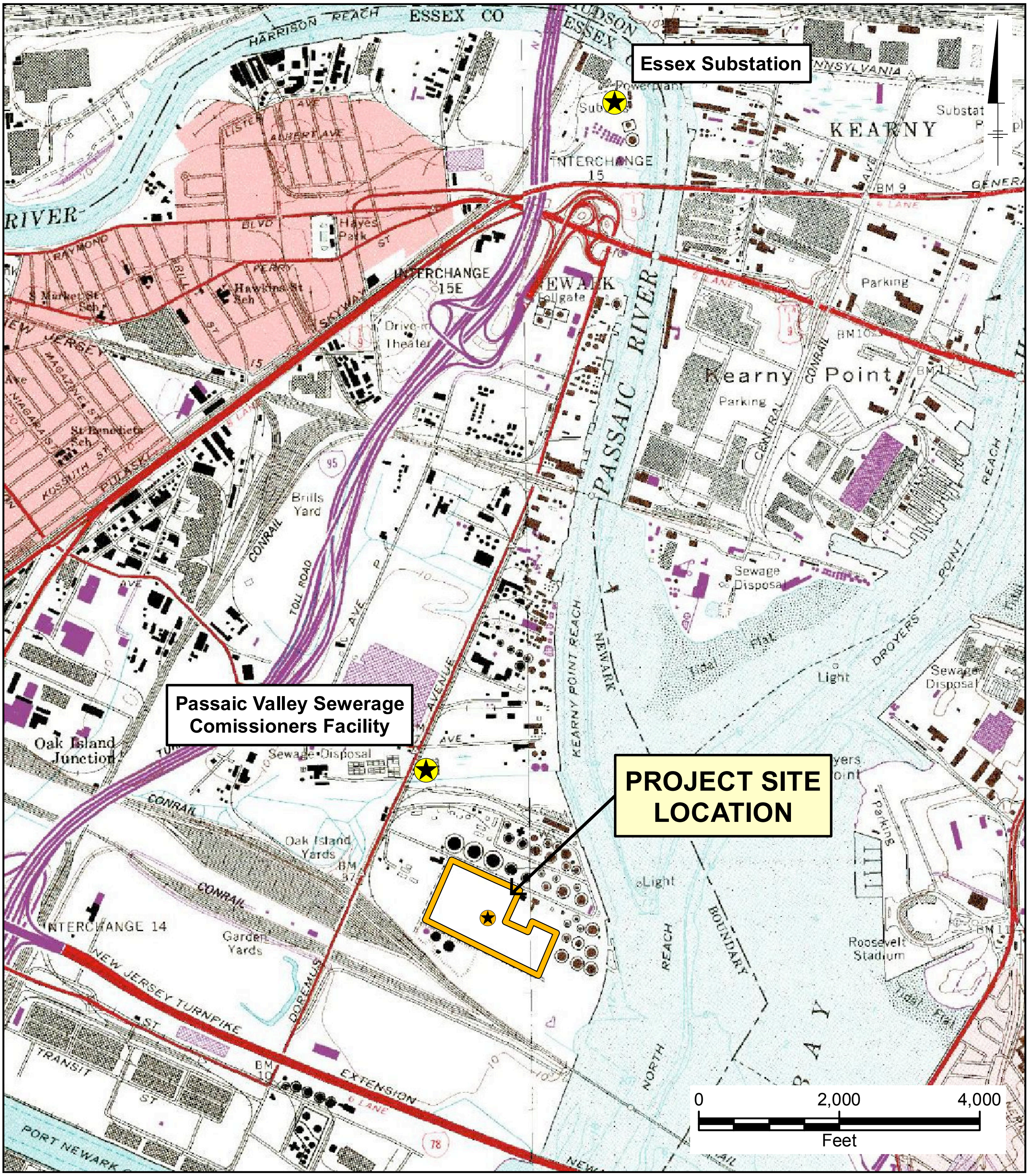
The project site is 25-acres and is zoned “I3” in an industrialized section of the City of Newark referred to as the “Third Industrial District.” The site is bounded on the east by a portion of the Hess Terminal and is situated more than 500 feet from Newark Bay. The northern boundary is bordered by Delancy Street. To the south, the property is bordered by a vacant lot, which abuts the Conrail Oak Island rail yard, and to the northwest the site is adjacent to property owned by the City of Newark and Propane Power. Doremus Avenue and the PVSC buildings are located further to the northwest.

2.3 Combined Cycle Combustion Turbines

The major equipment will include two (2) “F” class CTGs, two (2) supplementary-fired HRSGs, one (1) STG, and a mechanical draft wet cooling tower. This equipment is described in more detail below.

2.3.1 Combustion Turbine Generators

Thermal energy is produced in the two CTGs through the combustion of natural gas. Each CTG is capable of running independently of the other. The thermal energy is converted to mechanical energy in the CTG turbine that drives the CTG compressor and electric generator. The maximum heat input rate of each CTG for 100 percent load at International Organization for Standards (ISO) temperature and relative humidity (59 degrees Fahrenheit [°F] and 60 percent, respectively) and a site pressure of 14.5 pounds per square inch absolute (psia) is 2,080 million Btu per hour (MMBtu/hr) at the higher heating value (HHV) for natural gas.

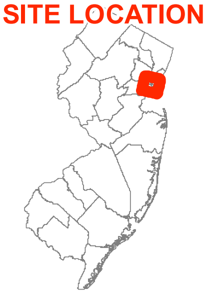


Legend

★ Project Area Center
NJ State Plane Coordinates (ft):
X: 595599 Y: 682504

▭ Newark Energy Center Project Area

BASE: 1:24k USGS 7.5 Minute Series
Topographic Map. Elizabeth and Jersey
City, NJ Quads



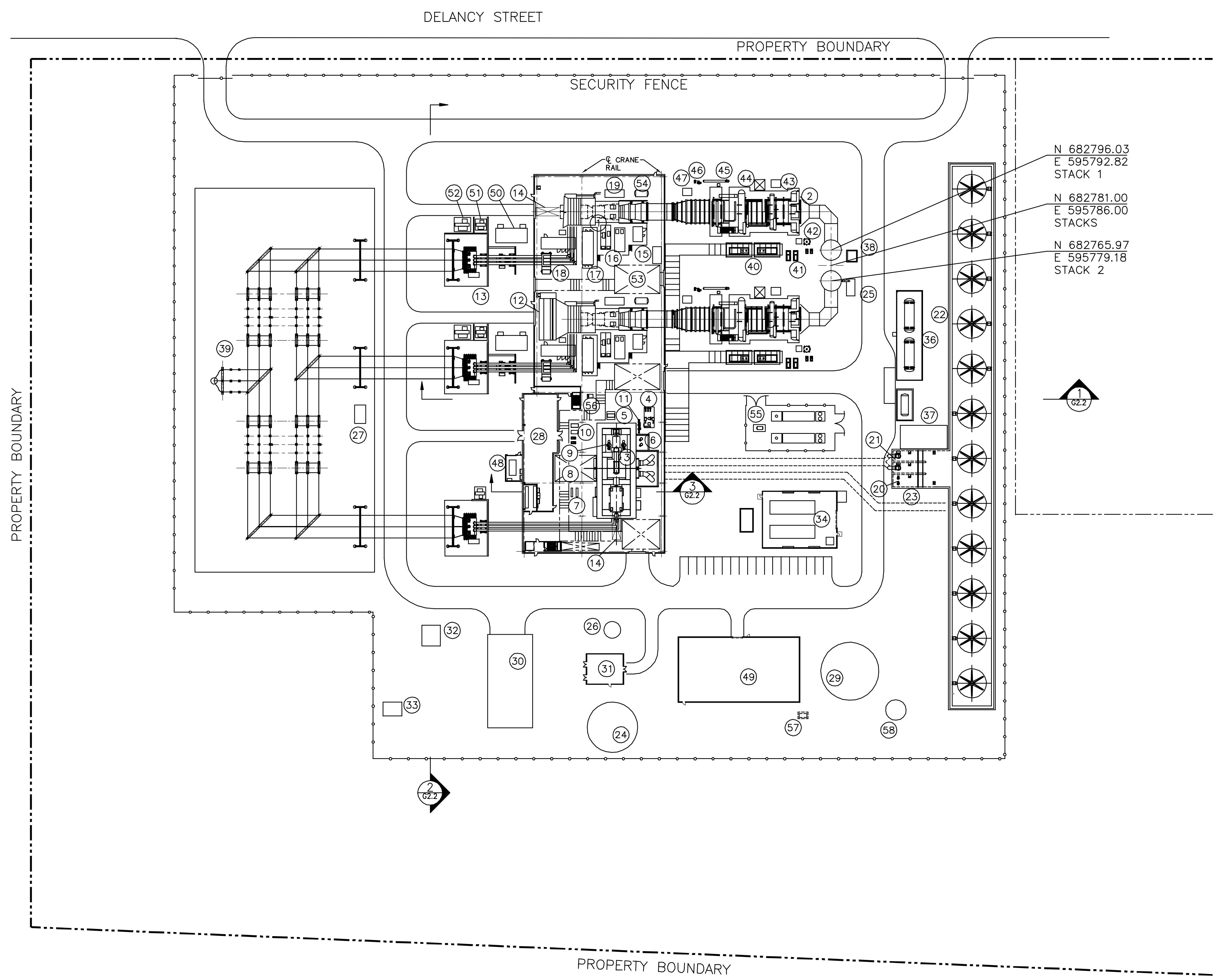
NEWARK ENERGY CENTER, LLC
NEWARK, ESSEX COUNTY, NEW JERSEY

SITE LOCATION MAP

ARCADIS

FIGURE
2-1

CITY: DIV/GROUP: DB: LD: PIC: PM: TM: TR:
Project (Project #)
G:\Aproject\GIS\Projects\PP_Misc\20101202_HESS_NJMXD\HESS_SiteLocation20111005.mxd - 10/5/2011 @ 11:41:34 AM



LEGEND:

1. COMBUSTION TURBINE
2. HRSG
3. STEAM TURBINE
4. STEAM TURBINE LUBE OIL EQUIPMENT
5. HYDRAULIC POWER UNIT
6. CONDENSATE PUMPS
7. CONDENSER VACUUM PUMPS
8. CONDENSER TUBE REMOVAL AREA
9. MAIN STEAM STOP VALVES
10. AUXILIARY COOLING WATER EQUIPMENT
11. GLAND STEAM CONDENSER
12. COMBUSTION TURBINE AIR INTAKE
13. MAIN STEP UP TRANSFORMER
14. GENERATOR ROTOR REMOVAL
15. WATER WASH SKID
16. COMBUSTION TURBINE AUXILIARY EQUIP SKIDS
17. PEEC COMPARTMENT
18. GENERATOR CIRCUIT BREAKER
19. WASTE WATER SUMP
20. AUX COOLING PUMP
21. CIRC WATER PUMPS
22. COOLING TOWER
23. CIRC WATER PUMP HOUSE
24. RAW WATER STORAGE TANK
25. AUXILIARY BOILER
26. DEMINERALIZED WATER STORAGE TANK
27. SWITCHGEAR CONTROL BUILDING
28. ELECTRICAL EQUIP (1ST FL) ADMIN/CONTROL (2ND FL)
29. TREATED WATER STORAGE TANK
30. MAINTENANCE / WAREHOUSE BUILDING
31. FIRE / WATER PUMP BUILDING
32. BACKFLOW PREVENTER HOUSE
33. FUEL GAS METER BUILDING
34. FUEL GAS COMPRESSOR BUILDING
35. STORMWATER DETENTION BASIN
36. AMMONIA STORAGE TANKS
37. CIRC WATER CHEMICAL BUILDING
38. CEMS BUILDING
39. SWITCHYARD
40. BOILER FEED PUMPS
41. IP FEEDWATER PUMPS
42. BOILER BLOWDOWN TANK, PUMPS AND SUMP
43. AMMONIA VAPORIZATION SKID
44. SCR REMOVAL AREA
45. FUEL GAS HEATER
46. FUEL GAS FILTER
47. DUCT BURNER SKID
48. EMERGENCY DIESEL BUILDING
49. WATER TREATMENT BUILDING
50. REMOTE I/O CABINET
51. EXCITATION TRANSFORMER
52. STATIC START ISOLATION TRANSFORMER
53. EQUIPMENT LAYDOWN AREA
54. FIRE PROTECTION CO2 SKID
55. FUEL GAS CONDITIONING EQUIPMENT AREA
56. WASTE WATER SUMP AND PUMPS
57. OIL WATER SEPARATOR
58. WASTE WATER COLLECTION TANK

APPROVED: ____________
REGISTERED PROFESSIONAL ENGINEER NO.
STATE OF NEW JERSEY

ISSUE	DATE	DESCRIPTION	BY	CHK'D
3	10/5/11	REVISED AMMONIA STORAGE TANKS	JCM	RJL
2	6/21/11	MINOR REVISION	JCM	RJL
1	4/19/11	ISSUED FOR DBD	JCM	RJL

PB Power
A PB Americas, Inc. Company
75 ARLINGTON STREET, BOSTON, MASS. 02116

NEWARK ENERGY CENTER
640 MW COMBINED CYCLE PLANT

Figure 2-2 - Site Plan

DR. JCM
DES.
CHK.
APPROVED DATE
PRINCIPAL IN CHARGE DATE
DRAWING NO. G2.1
REV 3
SHEET OF

\26142A HESS NEWARK PROJECT\

2.3.2 Heat Recovery Steam Generators and Duct Burners

In the combined-cycle configuration, each CTG will exhaust through a dedicated HRSG to generate steam from the waste heat energy in the exhaust gas. Each HRSG will be equipped with supplemental fuel firing via a duct burner. The duct burners provide additional energy to the HRSG, which produces more steam that can be fed to the STG. The duct burners will be natural gas fired and each will have a maximum input capacity of 211 MMBtu/hr (HHV), although the duct burners will not always operate at maximum capacity. The use of the duct burner will vary based upon different temperature and operating conditions.

2.3.3 Steam Turbine Generator

Steam generated in the HRSGs will be expanded through a STG multi-stage, reheat, condensing turbine and associated electric generator to generate additional electricity.

2.3.4 Cooling Tower

The steam condenser cooling will utilize a 12-cell mechanical draft wet cooling tower system. In a cooling tower, circulating water is distributed among multiple cells of the cooling tower, where it cascades downward through each cell and then collects in the cooling tower basin. The mechanical draft cooling tower employs electric motor-driven fans to move air through each cooling tower cell. The cascading circulating water is partially evaporated and the evaporated water is dispersed to the atmosphere as part of the moist air leaving each cooling tower cell. The circulating water is cooled primarily through its partial evaporation. The cooling tower will be equipped with Marley ClearSky plume abatement and with a high-efficiency drift eliminator with an efficiency of 0.0005 percent.

2.4 Air Pollution Control Equipment

The emission control technologies proposed for the combustion turbine and duct burner exhaust gases include dry low-NO_x (DLN) combustors which are integrated within the combustion turbines, and SCR systems and oxidation catalysts which are located within each HRSG to control NO_x, CO and VOC emissions. The DLN combustion controls NO_x formation by pre-mixing fuel and air immediately prior to combustion. Pre-mixing inhibits NO_x formation by minimizing both the flame temperature and the concentration of oxygen at the flame front. Oxidation catalysts control emissions of CO and VOC. Emissions of

SO_2, PM_{10}/$PM_{2.5}$, and H_2SO_4 will be minimized through the exclusive use of pipeline quality natural gas in the combustion turbines. The SCR and oxidation catalyst are discussed further in the sections below.

2.4.1 Selective Catalytic Reduction

SCR, a post-combustion chemical process, will be installed in the HRSGs to treat exhaust gases downstream of the CTGs. The SCR process will use 19 percent aqueous NH_3 as a reagent. Aqueous NH_3 will be injected into the flue gas stream, upstream of the SCR catalyst, where it will mix with NO_x. The catalyst bed will be located in a temperature zone of the HRSG where the catalyst is most effective. The mixture will pass over the catalyst and the NO_x will be reduced to nitrogen gas and water. The SCR system will reduce NO_x concentrations to 2.0 parts per million by volume (ppm_v) at 15 percent oxygen (O_2) with or without duct firing at all load conditions and ambient temperatures. A small amount of NH_3 will remain un-reacted through the catalyst, which is called the "ammonia slip." The NH_3 slip will be limited to 5.0 ppm_v at all load conditions and ambient temperatures.

2.4.2 Oxidation Catalyst

An oxidation catalyst system will be located within each HRSG to control emissions of CO and VOC. Exhaust gases from the turbines will be passed over a catalyst bed where excess air will oxidize the CO and VOC to form carbon dioxide (CO_2) and water. The oxidation catalyst system will reduce CO concentrations to 2.0 ppm_v (at 15 percent [%] O_2) in the exhaust gas under all load conditions and ambient temperatures. The oxidation catalyst will also reduce VOC emissions.

2.5 Ancillary Equipment

The proposed project will utilize a variety of ancillary equipment to support the facility including an auxiliary boiler, an emergency generator, an emergency fire pump, and storage tanks. This equipment is discussed further in the sections below.

2.5.1 Auxiliary Boiler

An auxiliary boiler will operate as needed to keep the HRSG warm during periods of turbine shutdown and provide sealing steam to the steam turbine during warm and hot starts. The auxiliary boiler will have a maximum input capacity of 66.2 MMBtu/hr and will be limited to 800 hours per year of operation.

2.5.2 Emergency Diesel Generator

The project will have a 1,500 kW emergency diesel generator provide on-site emergency power capabilities independent of the utility grid. The emergency generator will fire Ultra-Low Sulfur Diesel (ULSD) fuel and will typically only operate for testing and to maintain operational readiness in the event of an emergency. Per New Jersey Department of Environmental Protection (NJDEP) guidance, routine operation of the generator will be limited to a maximum of 100 operating hours per year, with each testing event limited to 30 minutes. Testing of the emergency diesel generator will not occur during startup or shutdown of the turbine or boilers. No testing will occur on state designated Ozone Action Days. There will be no simultaneous testing of the emergency generator and fire pump.

2.5.3 Emergency Diesel Fire Pump

The project will have a back-up fire pump to provide on-site fire fighting capabilities independent of the utility grid. The emergency fire pump will fire ULSD fuel and will typically only operate for testing and to maintain operational readiness in the event of an emergency. Similar to the emergency generator, it will be limited to a maximum of 100 operating hours per year, with each testing event limited to 30 minutes. Testing of the emergency fire pump will not occur during startup or shutdown of the turbine or boilers. No testing will occur on state designated Ozone Action Days. There will be no simultaneous testing of the emergency generator and fire pump.

2.5.4 Aqueous NH_3 Storage Tank

The proposed facility will have two nominal 20,000-gallon tanks that will store 19 percent aqueous NH_3 for use in the SCR system. The tanks will be equipped with secondary containment sized to accommodate the entire volume of one tank and sufficient freeboard for precipitation. The tanks will be located outdoors within an impermeable containment area, surrounded by a wall. The floor of the containment area will be covered with plastic balls designed to float on the liquid surface in the event of a spill, thereby reducing the exposed surface area, and minimizing potential emissions.

2.6 Emissions Estimates

The combined cycle units will typically operate at or near full load capacity to respond to electricity demands as needed. Depending upon the demand, each unit can operate at loads ranging from 52.9 percent plant load without supplemental duct firing to 100 percent load with supplemental duct firing (full capacity). Combustion turbine performance and emissions are affected by ambient conditions: humidity, pressure and temperature; with turbine fuel consumption, power output and emissions increasing at lower ambient temperatures. Supplemental duct firing performance and emissions are affected indirectly by ambient conditions, with fuel consumption, heat output and emissions increasing at higher ambient temperatures. As the combustion turbine decreases heat output to the HRSG at higher ambient temperatures, the supplemental duct firing increases to make up the loss of heat output to maintain maximum steam production to the steam turbine.

Table 2-1 presents a summary of the proposed limits for pollutants emitted from combined cycle combustion turbines at steady state full load operation. The limits reflect the application of SOTA, BACT, and LAER (Section 4.0).

Table 2-1: Summary of Proposed Emission Limits for Combined Cycle Combustion Turbines (Steady State Full Load Operation)[a]

Pollutant	Case	Emission Rate (lb/MMBtu)[b]	Emission Rate (ppm_v)[c]	Represents
NO_x	CT Only CT with DB[d]	0.0081 0.0081	2.0 2.0	LAER
VOC	CT Only CT with DB	0.0015 0.0029	1.0 2.0	LAER
CO	CT Only CT with DB	0.0050 0.0050	2.0 2.0	BACT/SOTA
$PM_{10}/PM_{2.5}$	CT Only CT with DB	0.0057 0.0064	n/a n/a	BACT/SOTA
SO_2	CT Only CT with DB	0.00037 0.00037	n/a n/a	SOTA
H_2SO4	CT Only CT with DB	0.00020 0.00020	n/a n/a	SOTA

a. Facility may exceed these limits during defined periods of startup and shutdown.
b. Emission Rates are based on lower heating value (LHV) of natural gas.
c. Concentrations are ppm_v at 15% O_2.
d. Duct burner.

Because of the different emission rates and exhaust characteristics, a matrix of operation modes will be evaluated in the NEC Dispersion Modeling Report.

Combined cycle start-up and shutdown scenarios are also addressed in this air permit application. Start-up and shutdown conditions refer to times when the CTG operates below the minimum operating load (52.9 percent), which may, for some pollutants, result in an increase in short term (pounds per hour [lb/hr]) emission rates. There is a minimum turbine downtime and maximum duration associated with each type of start-up. There is also a maximum duration associated with each shutdown. Potential annual emissions estimates for the proposed project include emissions from start-up and shutdown.

The following sections provide estimated emissions from the combined cycle combustion turbines and from the facility's ancillary equipment. Emissions of air contaminants from this equipment have been estimated based upon vendor emission guarantees, USEPA emission factors, mass balance calculations and engineering estimates.

2.6.1 Combined Cycle Combustion Turbine Emissions – Steady State Operation

Table 2-2 presents short term (lb/hr) emissions estimates from each combined cycle turbine under ISO conditions at several load conditions including duct burner operations. These emissions were developed from vendor estimates. The $PM_{10}/PM_{2.5}$ emissions estimates include filterable and condensable particulate matter and an allowance for sulfate and/or ammonia salt formation due to the reaction of sulfur trioxide (SO_3) with water and/or excess NH_3 in the SCR and oxidation catalyst systems. Emission rates for all operating conditions are provided in Appendix B.

Potential non-criteria pollutant emissions from the operation of the combustion turbines and ancillary equipment were estimated using AP-42 emission factors with the following exceptions. Emissions of formaldehyde from the combustion turbine generators were estimated using an emission factor from a California Air Resource Board (CARB) database. The California Air Toxics Emission Factor (CATEF) database contains air toxics emission factors calculated from source test data collected for California's Air Toxics Hot Spots Program (CARB, 1996). Emissions of hexane from the duct burner and the auxiliary boiler were estimated using an emission factor from the Ventura County Air Pollution Control District (VCAPCD, 2001). In both cases, the AP-42 emission factors had a very low emission factor rating and were not considered representative of the proposed equipment. The CARB and VCAPCD emission factors are considered more appropriate for the advanced technology of the GE 7FA.05 combustion turbines. Potential emissions of Hazardous Air Pollutants (HAPs) and NJDEP air toxics from operation of the combustion turbines and duct burners are also provided in Appendix B.

Table 2-2: Summary of Short Term Emission Rates for a Single Combustion Turbine[a]

Pollutant	100% Load with Duct Burning (lb/hr)	100% Load without Duct Burning (lb/hr)	~80% Load without Duct Burning[b] (lb/hr)	~60% Load without Duct Burning[b] (lb/hr)
NO_x	16.4	15.1	12.2	9.3
VOC	5.7	2.6	2.1	1.6
CO	10.0	9.2	7.4	5.7
$PM_{10}/PM_{2.5}$	11.9	9.9	9.7	9.6
SO_2	0.76	0.69	0.56	0.42
H_2SO_4	0.41	0.37	0.30	0.23
NH_3	14.0	14.0	12.0	9.0

a. Emissions presented in table are for ISO conditions. These may not represent worst-case conditions for purposes of potential annual emission estimates and air quality dispersion modeling. Appropriate worst-case conditions will be used for these analyses in the NEC Dispersion Modeling Report.

2.6.2 Combined Cycle Combustion Turbine Emissions – Start-up and Shutdown Operations

Potential emissions associated with startup and shutdown of the combustion turbines were developed using vendor supplied information. Table 2-3 presents the emissions and downtimes (minimum number of hours the turbines would be off before a re-start) associated with startup and shutdown events for the combined cycle turbines. In most cases, emissions from these events are “self correcting” on an annual basis. In other words, the average hourly emissions for each startup event (including downtime) are less than the corresponding steady state emission rate for the minimum downtime that would precede a start. Table 2-3 identifies the pollutants that are self-correcting for each event. Permitted annual emission limits for the facility incorporates those conditions that are not considered self-correcting. Table 2-4 presents the average hourly emission rates associated with each startup/shutdown event. These emission rates incorporate the minimum downtime that would precede each event. These average hourly rates were used to determine if the event was considered self-correcting compared to steady state emission rates. Emissions of SO_2 will always be self-correcting because SO_2 emissions are dependent upon the amount of fuel burned, and steady state is always worst-case.

Table 2-3: Emissions and Downtimes Associated with Start-up and Shutdown Events

	Cold Startup	Hot Startup	Warm Start-up	Shutdown
Number of Events per Year	50	0[a]	250	300
Minimum Downtime Preceding Event (hrs)[b]	72	4	8	1
Duration of Event (min)[c]	185	39	75	18
	Emissions Per Event (lb)[d]			
PM$_{10}$/PM$_{2.5}$	37	8	15	4
NO$_x$	471	90	163	25
CO	2500	550	693	546
VOC	142	26	40	14
	Self-Correcting			
PM$_{10}$/PM$_{2.5}$	Yes	Yes	Yes	Yes
NO$_x$	Yes	No	No	No
CO	No	No	No	No
VOC	Yes	No	No	No

a. Total hot start and warm start emissions are 250. Emissions were conservatively estimated assuming warm starts because hot start emissions are lower.

b. hours

c. minutes

d. pounds

Table 2-4: Average Hourly Emissions for Start-up and Shutdown Events (including downtime)

Pollutant	Cold Startup (lb/hr)	Hot Startup (lb/hr)	Warm Start-up (lb/hr)	Shutdown (lb/hr)
PM$_{10}$/PM$_{2.5}$	0.49	1.72	1.62	3.08
NO$_x$	6.27	19.35	17.62	19.23
CO	33.30	118.28	74.92	420.00
VOC	1.89	5.59	4.32	10.77

2.6.3 Ancillary Equipment

This section presents estimated criteria pollutant emissions from the ancillary equipment at the facility. The proposed ancillary equipment includes one auxiliary boiler, one emergency generator, one emergency fire pump, and the cooling tower. The following assumptions were used in evaluating emissions from this equipment:

- The natural gas-fired auxiliary boiler will have a maximum input capacity of 66.2 MMBtu/hr and be limited to 800 hours of operation per year.
- The diesel-fired emergency fire pump will have a maximum heat input of 2.1 MMBtu/hr (15 gallons per hour) and will be limited to 100 hours of operation per year. For load testing, the diesel fire pump will limit operations to 30 minutes in any hour.
- The diesel-fired emergency generator will have a maximum heat input of 14.4 MMBtu/hr (105 gallons per hour) and will be limited to 100 hours of operation per year. For testing, the emergency generator will limit operations to 30 minutes in any hour.
- The cooling tower is expected to average 2.5 MGD, with a maximum use of 5.4 MGD.

Criteria pollutant emissions from the ancillary equipment were estimated based on vendor supplied information except for SO_2 emissions from the emergency equipment, which are based on a mass balance assuming ULSD. $PM_{10}/PM_{2.5}$ emissions from the cooling tower are based upon design values and conservatively assume five cycles of concentration. The cooling tower will utilize a high efficiency drift eliminator.

Tables 2-5 and 2-6 summarize estimated short-term (lb/hr) and annual emissions of criteria pollutants from the ancillary equipment. Supporting calculations are located in Appendix B.

Table 2-5: Short-Term Potential Emissions from Ancillary Equipment

Pollutant	Auxiliary Boiler (lb/hr)	Emergency Fire Pump		Emergency Generator (lb/hr)		Cooling Tower (lb/hr)
		lb/hr	lb/event[a]	lb/hr	lb/event[a]	
PM_{10}	0.66	0.09	0.045	0.66	0.33	1.26
$PM_{2.5}$	0.66	0.09	0.045	0.66	0.33	0.57
SO_2	0.03	0.002	0.001	0.016	0.008	--
NO_x	1.32	1.56	0.78	18.53	9.26	--
CO	2.45	1.56	0.78	11.56	5.78	--
VOC	0.33	0.22	0.11	2.62	1.31	--
Pb	0.00	0.00002	0.00001	0.0002	0.0001	--

a. Potential hourly emissions for the fire pump are based on a restriction of 30 operating minutes per hour during testing.

b. Potential hourly emissions for the emergency generator are based on a restriction of 30 operating minutes per hour during testing.

Table 2-6: Potential Annual Emissions from Ancillary Equipment

Pollutant	Auxiliary Boiler (tpy)	Emergency Fire Pump (tpy)	Emergency Generator (tpy)	Cooling Tower (tpy)	Total (tpy)
PM_{10}	0.26	0.004	0.03	5.5	5.79
$PM_{2.5}$	0.26	0.004	0.03	2.5	2.79
SO_2	0.01	0.0001	0.001	--	0.01
NO_x	0.53	0.08	0.93	--	1.54
CO	0.98	0.08	0.58	--	1.64
VOC	0.13	0.01	0.13	--	0.27
Pb	0.00	0.000001	0.00001	--	0.000011

HAP emissions will be less than major source thresholds, less than 10 tpy for any individual HAP and 25 tpy for total HAPs. Calculations of potential HAP and NJDEP air toxic emissions from the ancillary equipment are provided in Appendix B.

2.6.4 Potential Annual Emissions

Potential annual emissions from the proposed facility were estimated using the following worst-case assumptions:

- Full load operation of the combustion turbines (at 59°F ambient temperature);
- Duct burning for 1,800 hours per year during steady state operation of each combustion turbine;
- Incorporation of startup/shutdown events as described in Section 2.6.2; for start-up/shutdown events that are not self correcting, a total of 300 combined start-up events per year and 300 shutdown events per year were assumed (see Table 2-3); and
- Incorporation of emissions from ancillary equipment as discussed in Section 2.6.3 (see Table 2-6).

Potential annual emissions for the proposed project are summarized in Table 2-7.

Table 2-7: Summary of Annual Potential Emissions

Pollutant	Combustion Turbines (tpy)	Ancillary Equipment (tpy)	Total (tpy)
PM_{10}	90.3	5.79	96.1
$PM_{2.5}$	90.3	2.79	93.1
SO_2	6.2	0.01	6.2
NO_x	142.1	1.54	143.6
CO	484.7	1.64	486.3
VOC	35.5	0.27	35.8
H_2SO_4	3.3	0.001	3.3
NH_3	122.6	0.0	122.6
Pb	0.0	0.00001	0.00001

2.7 Alternative Sites, Sizes and Production Processes

PSD and NJDEP review requires an analysis of alternative sites, sizes, and production processes which demonstrates that the benefits of the proposed project significantly outweigh its environmental and social costs. NEC considered these alternatives as described below.

2.7.1 Alternative Sites

The purpose of this project is to provide a nominal 655 MW of electricity to respond to regional energy needs using only clean-burning natural gas technology. The Hess NEC site was selected due to its ideal location. The proposed NEC site is close to an adequate and easily accessible gas supply and an interconnection point (the PSEG Essex Substation). The site has a readily available supply of cooling water. NEC is proposing to use treated effluent from PVSC, which also has readily available treatment capacity. In addition, it is situated in an area surrounded by other industrial land uses and is well-removed from residential areas. No other sites are within NEC's control that would be more suitable.

2.7.2 Alternative Sizes

NEC proposes to develop a combined cycle power plant using two F-Class combustion turbines. The two units will operate independently, with each unit capable of generating approximately 211 MW (nominally). This will enable the project to respond to changing electric demand conditions. NEC considered alternate turbine sizes. Larger class turbines (G or H), because of their increased electrical output, provide less flexibility. Smaller turbines (aero-derivatives) cannot match F-Class turbines' superior environmental performance (lb/MW-hr). Therefore, NEC proposes to use F-Class turbines.

NEC considered projects with fewer and greater numbers of units. A project with one unit, while having commensurately lower emission levels, would not afford the economies of scale with respect to other environmental considerations (e.g., site development, aesthetics, and traffic). A project with three or more units would exceed the proposed transmission interconnection system's capacity and would also exceed site space limitations.

2.7.3 Alternative Production Processes

Technology alternatives considered included simple cycle combustion turbine technology and conventional boiler technology. Simple cycle turbines and conventional boilers are not as efficient as combined cycle units in terms of both energy (MW per Btu of fuel) and environmental (lbs of emissions per MW) efficiency.

Simple cycle technology is typically applied to meet intermittent or peak electrical demand. The project is being developed to meet growing base-load electrical demand. As such, combined cycle technology is the superior alternative.

In addition to being less energy and environmentally efficient, all of the electrical output of conventional boiler technology is from the steam cycle, resulting in considerably greater water demand than for a combined cycle project. For these reasons, combined cycle technology was determined to be the superior alternative.

.

3. REGULATORY APPLICABILITY EVALUATION

NEC is requesting approval to construct a nominal 655 MW combined cycle electric generating facility in the City of Newark, Essex County, New Jersey. The project is considered a new major stationary combustion source under PSD and NNSR regulations because the potential annual emissions from the facility exceed major source thresholds as illustrated in Table 1-1.

This section contains an analysis of the applicability of federal and state air quality regulations to the proposed project. The specific regulations and programs that are included in this review include:

- NNSR
- PSD New Source Review
- Federal New Source Performance Standards (NSPS)
- Federal National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Federal Acid Rain Program
- Other NJDEP Requirements
- Accidental Release Requirements

3.1 Nonattainment New Source Review

This section discusses Non-attainment New Source Review (NNSR) requirements and analyses required pursuant to New Jersey Administrative Code (NJAC) Title 7, Chapter 27, Subchapters 8, 13, 18, and 22.

USEPA has established primary and secondary NAAQS for criteria pollutants that are designed to protect public health and welfare. The six criteria pollutants are SO_2, particulate matter (PM), nitrogen dioxide (NO_2), CO, O_3 and Pb. Particulate matter is further classified as either PM_{10} or $PM_{2.5}$. The results of clinical and epidemiological studies were used to establish the primary NAAQS to protect public health, including the health of “sensitive” populations. The secondary NAAQS protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. USEPA has established both short-term and long-term standards.

New Jersey has adopted NJAAQS for the criteria pollutants, but categorizes particulate matter only as TSP. The NJAAQS have similar thresholds to the NAAQS, but include different averaging times, as indicated in Table 3-1.

Table 3-1: Summary of Primary Federal and State Ambient Air Quality Standards

Pollutant	Averaging Period	Ambient Air Quality Standards	
		NAAQS ($\mu g/m^3$) [a]	NJAAQS ($\mu g/m^3$) [b]
SO_2	1-hour	196 [c]	--
	3-hour	1,300	1,300
	24-hour	365	365
	Annual / 12 month	80	80
TSP	24-hour	--	260
	12-month	--	75 [d]
PM_{10}	24-hour	150 [e]	--
$PM_{2.5}$	24-hour	35 [f]	--
	Annual	15	--
CO	1-hour	40,000	40,000
	8-hour	10,000	10,000
NO_2	1-hour	188 [g]	--
	Annual / 12 month	100	100
O_3	8-hour	160 [h]	160
	24-hour	--	--
Pb	3-month	0.15 [i]	1.5

a. All short-term NAAQS (1-, 3-, 8-, and 24-hr) standards except O_3, $PM_{2.5}$ and PM_{10} are not to be exceeded more than once per calendar year. 3-month and annual standards are never to be exceeded.

b. All short-term NJAAQS (1-, 3-, 8-, and 24-) standards except O_3 are not to be exceeded more than once per 12 month period; 3-month and 12-month standards are never to be exceeded. All averages are calculated as running or moving averages.

c. For the 1-hour SO_2 NAAQS, compliance is determined using the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor. The new 1-hour standard for SO_2 took effect on June 2, 2010. The new standard has not yet been incorporated into New Jersey air regulations.

d. The 12-month TSP standards are geometric means.

e. For 24-hour PM_{10}, USEPA 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.

f. For 24-hour $PM_{2.5}$, USEPA uses the 98% percentile 24-hour maximum concentration from the last three years of air quality monitoring data to determine a violation of the standard.

g. For the 1-hour NO_2 NAAQS, compliance is determined using the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor. The new 1-hour standard for NO_2 took effect on January 22, 2010.

h. For 8-hr ozone, USEPA 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. The new standard has not yet been incorporated into New Jersey air regulations.

i. The 3-month NAAQS for Pb is a moving average.

Areas of the country where pollutant concentrations persistently exceed the NAAQS are designated as nonattainment. Essex County is designated as a moderate nonattainment area with respect to the 8-hour ozone NAAQS and NJAAQS and as a nonattainment area with respect to annual and 24-hour $PM_{2.5}$ NAAQS. For NNSR permitting applicability and implementation, the NJDEP has retained the applicability thresholds pertaining to the 1-hour severe O_3 classification for VOC and NO_x. Therefore, new sources in New Jersey with potential emissions of 25 tpy or more of VOC or NO_x would be subject to NNSR. As such, the project will be subject to NNSR for NO_x and VOC. The major source threshold for $PM_{2.5}$ is 100 tpy. As shown in Table 1-1, the project is not subject to NNSR for $PM_{2.5}$.

The proposed project is designated as attainment or unclassifiable for SO_2, CO, NO_2, PM_{10} and Pb. Therefore, for these pollutants, the project is required to demonstrate compliance with the NJAAQS and NAAQS shown in Table 3-1 and are subject to PSD New Source Review (see Section 3.2).

Permitting requirements for new sources of air pollutants are contained in NJAC Title 7, Chapter 27, Subchapters 8, 18 and 22. Subchapter 8 contains the permitting requirements for minor sources and Subchapter 22 specifies requirements for major sources. The project will be subject to NNSR as a major source of ozone (O_3) precursors, NO_x and VOC. NNSR permitting requirements are given in NJAC Title 7, Chapter 27, Subchapter 18 and 22. These include the need to apply LAER technology and obtain NO_x and VOC offsets. Because O_3 is a regional pollutant, there is no ambient air quality modeling requirement to assess Project impacts for O_3.

Since the proposed Project will be a major source for NOx and VOC under NNSR, the requirements of Subchapter 18 (Emission Offset Rules) are applicable. NJAC 7:27-18.2(a) specifies the following emissions applicability thresholds:

- CO – 100 tons per year (tpy);
- Particulate matter less than 10 microns in diameter (PM10) – 100 tpy;
- Total suspended particulates (TSP) – 100 tpy;
- Sulfur dioxide (SO2) – 100 tpy;
- NO_x – 25 tpy;
- VOC – 25 tpy; and
- Lead (Pb) – 10 tpy.

Additionally, NJDEP's *Revised Interim Permitting and Modeling Procedures for New or Modified Sources Emitting between less than 100 Tons per Year of $PM_{2.5}$ (Fine Particulate) and Proposing between a 10 – 99 ton per year increase in $PM_{2.5}$* (December 14, 2010) sets the threshold for Subchapter 18 applicability at 100 tpy for $PM_{2.5}$. As presented in Table 1-1, potential emissions for the project exceed major source thresholds for CO, NOx and VOC.

Subchapter 18.7, Table 3 also prescribes significant net emission increase thresholds for criteria pollutants which must be applied if one or more pollutants meet or exceed the Subchapter 18 applicability threshold. These thresholds are:

- CO – 100 tpy;
- PM_{10} – 15 tpy;
- TSP – 25 tpy;
- SO_2 – 40 tpy;
- NO_x – 25 tpy;
- VOC – 25 tpy; and
- Pb – 0.6 tpy.

The NJDEP's December 2010 policy sets the significant net emission increase threshold for Subchapter 18 applicability at 10 tpy for $PM_{2.5}$.

Subchapter 18 specifies that if a project is classified as a major source for any pollutant, it is subject to significant net emission increase thresholds for all other pollutants emitted from that source. Since the project will be a major source for CO, NO_x and VOC, emissions of other criteria pollutants are subject to the significant net emission increase thresholds. Based upon annual emission estimates, the pollutants exceeding the significant emissions thresholds are CO, NO_x, VOC, TSP, PM_{10} and $PM_{2.5}$.

Proposed sources with emissions levels that exceed the Subchapter 18 applicability threshold for any pollutant must meet the following requirements for all pollutants with potential emissions greater than the pollutant's significant net emission increase threshold.

- LAER – The applicant must demonstrate that it will meet LAER for nonattainment pollutants that exceed the significant net emission increase threshold. For the project, this applies to NO_x and VOC. Requirements for $PM_{2.5}$ are slightly different as described below.

- Offsets – The applicant must secure offsets for the nonattainment pollutants for which the potential emissions are greater than the pollutant's significant net emission increase threshold. The offset ratios increase based on the distance of the offsets from the project's location. For the project, this applies to NO_x and VOC. Requirements for $PM_{2.5}$ are slightly different as described below.
- Alternatives Analysis – The applicant must submit an analysis of alternative sites, fuels, facility size, and control technologies for the project which demonstrates that having the project constructed outweighs the environmental and social costs of the project.
- Compliance Certification – The applicant must certify that all other projects owned or operated by the applicant in the State of New Jersey are in compliance with NJAC Chapter 27 and the federal Clean Air Act.
- Air Quality Impact Analysis – The applicant must provide dispersion modeling for the pollutants that exceed the significant net emission increase threshold to demonstrate that the predicted impacts from these pollutants would meet the National Ambient Air Quality Standards (NAAQS) and New Jersey Ambient Air Quality Standards (NJAAQS).

The NJDEP's December 2010 policy memorandum provides slightly different requirements for $PM_{2.5}$. For sources which exceed the 100 tpy major source threshold for $PM_{2.5}$, the full Subchapter 18 requirements discussed above are applicable, including LAER and offsets. Sources that emit less than 100 tpy, but exceed the 10 tpy significant net emission increase thresholds for $PM_{2.5}$ and are located in a designated nonattainment area with nearby representative monitored values below the NAAQS [these conditions apply to the project], must complete dispersion modeling for $PM_{2.5}$. Inclusion of other nearby large $PM_{2.5}$ sources in the modeling, if needed to more accurately define background $PM_{2.5}$ levels, will be determined on a case-by-case basis.

If the modeled $PM_{2.5}$ impact plus representative background exceeds the 24-hour or annual $PM_{2.5}$ NAAQS, then a determination is made whether the source's contribution to the NAAQS violation exceeds the $PM_{2.5}$ Significant Impact Level (SIL) for the relevant averaging time. If so, the source must take steps to eliminate the violation or reduce its impact below the SIL. Potential strategies for reducing its $PM_{2.5}$ impact include the following: reducing emissions, increasing stack height or obtaining emission offsets from existing sources. The emission offsets and other mitigation measures secured must be modeled to verify they result in the elimination of the predicted NAAQS violation or reduction in the source's impact to below the $PM_{2.5}$ SIL. The results of the required modeling are provided in the NEC Dispersion Modeling Report.

3.1.1 Lowest Achievable Emission Rate

Pollutants subject to NNSR are required to implement LAER technology for those pollutants. LAER is defined as the most stringent emission limitation achieved in practice, or which can reasonably be expected to occur in practice for a category of emission sources taking into consideration each air contaminant that must be controlled. The proposed project is considered major for both NO_x and VOC. As such, LAER technology will be applied for these two pollutants as described in Section 4.0 of this application.

3.1.2 Emissions Offsets

A major source or major modification planned in a designated nonattainment area must obtain emissions offsets as a condition of approval. Emissions offsets are generally obtained from existing sources located in the vicinity of the proposed source. The emission reductions must: (1) offset the emissions increase from the new source, and (2) provide a net air quality benefit. These offsets, obtained from existing sources that implement a permanent, enforceable, quantifiable and surplus emissions reduction, must equal the emissions increase from the new source multiplied by an offset ratio.

Permitting requirements for major sources of non-attainment pollutants are contained in NJAC 7:27-18, also referred to as NJDEP's Emissions Offset Rule. As described previously, Essex County is designated as a moderate nonattainment area with respect to the 8-hour ozone NAAQS and NJAAQS and as a nonattainment area with respect to annual and 24-hour $PM_{2.5}$ NAAQS. The emissions offset thresholds in NJDEP's Emissions Offset Rule for ozone precursors VOC and NO_x is 25 tpy. The project will exceed these thresholds, requiring 184.7 tons of emissions offsets for NO_x and 46.2 tons of emission offsets for VOC, assuming a offset ratio of 1.3 to 1. Sources for these offsets have not yet been identified. However, they will be a part of the NJDEP registry and satisfy NJDEP criteria This information will be provided to the Department prior to issuance of the air permit. Currently, $PM_{2.5}$ is not included in NJDEP's Emissions Offset Rule and offsets for $PM_{2.5}$ are handled in NJDEP's interim policy discussed in Section 3.1. Emissions offsets for $PM_{2.5}$ are not required for the project.

3.1.3 Certification of Compliance

NJAC 7:27-18.3(b)(2) requires a certification that all emission sources that are part of any major facility located in New Jersey or under the applicant's ownership or control are in compliance, or on a schedule for compliance, with all application emission limitations and standards. NEC neither owns nor manages any other facilities in New Jersey. As such, this requirement is not applicable to this project.

3.1.4 Analysis of Alternatives

NJAC 7:27-18.3(c)(2) requires an analysis of alternative sites, sizes, production processes, and environmental control techniques which demonstrates that the benefits of the proposed project significantly outweigh the environmental and social costs imposed as a result of its construction. A discussion of alternative sites, sizes and production processes considered is presented in Section 2.7. Alternative emission control technologies are identified and evaluated as part of the BACT/LAER analyses presented in Section 4.0. The analyses demonstrate that the proposed emission control technologies are representative of SOTA, BACT and LAER.

3.2 PSD New Source Review

Combined cycle power plants with potential emissions greater than 100 tpy of one or more criteria pollutants are considered new major stationary sources under the PSD program. As shown in Table 1-1, the potential emissions of at least one regulated criteria pollutant will exceed this threshold. As such, the proposed facility is subject to PSD New Source Review. Under the PSD regulations, once a major source threshold is triggered, PSD review must be completed for all pollutants whose potential emissions exceed their significant emission rate increase.

On April 2, 2007, the U.S. Supreme Court found that GHGs, including CO_2, are air pollutants covered by the Clean Air Act (CAA). On May 13, 2010, the USEPA issued a final rule (called the “Tailoring Rule”) that establishes an approach to GHG emissions from stationary sources under the CAA. This final rule “tailors” the requirements of the CAA permitting program to limit which facilities will be required to obtain PSD permits. The CAA permitting program emissions thresholds for criteria pollutants are 100 tons per year or 250 tons per year, depending on the source category. While these thresholds are appropriate for criteria pollutants, they are not feasible for GHG emissions as they are emitted in much greater quantities. USEPA will phase in the CAA permitting requirements in two phases:

- Only sources already subject to the PSD program (i.e., new major sources such as NEC) are subject to permitting requirements for their GHG emissions under PSD. For these projects, those with GHG emission increases of 75,000 tpy or greater are required to determine BACT for their GHG emissions. This phase began on January 2, 2011.

- In the second phase, PSD permitting requirements will cover new construction projects that exceed 100,000 tpy of GHG emissions, even if they do not exceed any other permitting thresholds. This began on July 1, 2011.

As presented in Table 1-1, NEC has triggered major source thresholds for GHGs. In addition, PSD review is required for NO_x, CO, VOC, and PM_{10} emissions.

PSD review requirements include application of BACT, an ambient air quality modeling analysis demonstrating compliance with NAAQS/NJAAQS and PSD increments, and an additional impacts analysis. New Jersey has been delegated PSD review authority by USEPA. For an air contaminant subject to BACT, compliance with BACT requirements also represents SOTA (NJAC 7:27-8.12(e)(2)).

3.2.1 Best Available Control Technology

Pollutants subject to PSD review are required to apply BACT for control of emissions of PSD pollutants. 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. In establishing the final BACT limit, USEPA may consider any new information, including recent permit decisions, subsequent to submittal of a complete application. Although the project is required to implement BACT for NO_2 under the PSD program, LAER is also required under NNSR. Since the LAER requirements are at least as stringent as BACT, the LAER analysis will satisfy BACT requirements for NO_2. The LAER analyses for NO_x and VOC, and the BACT analyses for CO, and PM_{10}, are presented in Section 4.0.

3.2.2 Air Quality Impact Analysis

An ambient air quality analysis must be performed to demonstrate compliance with NAAQS, NJAAQS and PSD increments. Proposed new sources subject to PSD review may not cause or significantly contribute to a violation of the NAAQS or NJAAQS. As part of this demonstration, the USEPA and NJDEP have established Significant Impact Levels (SILs) for all of the criteria pollutants. SILs represent concentrations of pollutants that are considered to be insignificant with respect to demonstration of NAAQS compliance. By definition, proposed new sources whose air quality impacts are less than SILs neither cause nor significantly contribute to NAAQS or NJAAQS violations. Proposed new sources whose air quality impacts exceed the SILs must compete a cumulative analysis taking into consideration existing background air quality levels and contributions from other sources.

The air quality impact analysis for the project is included in the NEC Dispersion Modeling Report.

3.2.3 PSD Class I Area Impact Analysis

PSD regulations require that proposed major sources within 100 kilometers (km) of a PSD Class I area perform an assessment of potential impacts in the PSD Class I area. PSD Class I areas are specifically designated areas of special national or regional value from a natural, scenic, recreational or historic perspective. These areas are administered by the National Park Service (NPS), U.S. Fish and Wildlife Service (USFWS), or the U.S. Forest Service (USFS). These Federal Land Managers (FLMs) are responsible for evaluating proposed projects' air quality impacts in the Class I areas and may make recommendations to the permitting agency to approve or deny permit applications.

PSD Class I area impact analyses consist of:

- An air quality impact analysis;
- A visibility impairment analysis; and
- An analysis of impacts on other air quality related values (AQRVs) such as impacts to flora and fauna, water, and cultural resources.

There are no PSD Class I areas within 100 km of the proposed project site. The closest designated PSD Class I area is the Brigantine Wilderness Area, located 135 km south of the project.

Based on the level of proposed emissions from the project and the distances to the nearest PSD Class I area, the project is not required to complete PSD Class I impact modeling.

3.2.4 Additional Impact Analyses

Additional impact analyses are also required as part of PSD review and NJDEP regulations. These additional analyses include an assessment of impacts on community growth resulting from the project, an assessment of visibility impairment and an assessment of impacts to soils and vegetation. These impact analyses are presented in the NEC Dispersion Modeling Report. NEC has also conducted an impact analysis for cooling tower fogging and icing.

The Endangered Species Act of 1973 requires that all federal actions, such as the issuance of PSD permits, not jeopardize the existence of any endangered or threatened species or result in the destruction or adverse modification of the habitat of such species. NEC has consulted with the USFWS. Records of these communications will be provided in the NEC Dispersion Modeling Report.

3.3 New Source Performance Standards

NSPS are technology-based standards applicable to new and modified stationary sources. NSPS have been established for approximately 70 source categories. Based upon a review of these standards, several subparts are applicable to the proposed project. The project's compliance with each of these standards is presented in the sections below.

3.3.1 40 CFR 60 – Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions under Subpart A. Because the project is subject to other Subparts of the regulation, the requirements of Subpart A will also apply. NEC will comply with the applicable notifications, performance testing, recordkeeping and reporting outlined in Subpart A.

3.3.2 40 CFR 60 – Subpart KKKK – Stationary Combustion Turbines

Subpart KKKK places emission limits on NO_x and SO_2 from new combustion turbines. The proposed combustion turbines and duct burners would be subject to this standard. For new combustion turbines firing natural gas with a rated heat input greater than 850 MMBtu/hr, NO_x emissions are limited to:

- 15 ppm_v at 15 percent O_2; or
- 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour [lb/MW-hr]).

Additionally, SO_2 emissions must meet one of the following:

- Emissions limited to 110 ng/J (0.90 lb/MW-hr) gross output; or

- Emissions limited to 26 ng/J (0.060 lb/MMBtu).

As described in Section 2.0, the proposed project will use an SCR system to reduce NO_x emissions to 2 ppm_v at 15 percent O_2 and pipeline natural gas to limit SO_2 emissions to 0.00037 lb/MMBtu. As such, the project will meet the emission limits under Subpart KKKK.

Additionally, the provisions of this Subpart require continuous monitoring of water-to-fuel ratio, but allow for the use of either a 40 CFR Part 60 or Part 75 certified NO_x CEMS in lieu of this requirement. NEC is proposing to use a 40 CFR Part 75 certified NO_x CEMS, which will satisfy this requirement.

3.3.3 40 CFR 60 – Subpart Dc – Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc is applicable to steam generating units with a maximum input capacity greater than 10 MMBtu/hr and less than 100 MMBtu/hr. The proposed auxiliary boiler has a maximum input capacity of 66.2 MMBtu/hr, and is, therefore, subject to the standard. For units combusting natural gas, the standard requires initial notifications at the start of construction and at startup. 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 proposed boiler, there are no specific reporting requirements to the USEPA under Subpart Dc.

3.3.4 40 CFR 60 – Subpart IIII – Stationary Compression Ignition Internal Combustion Engines

Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines that commence operation after July 11, 2005. Relevant to the proposed project, this rule applies to the emergency generator and emergency fire pump.

For model year 2009 and later fire pump engines with a displacement less than 30 liters per cylinder and an energy rating between 300 and 600 horsepower (hp), Subpart IIII provides the following emission limits:

- 4.0 grams per kilowatt-hour (g/kW-hr) (3.0 grams per horsepower-hour [g/hp-hr]) of VOC + NO_x
- 3.5 g/kW-hr (2.6 g/hp-hr) of CO
- 0.2 g/kW-hr (0.15 g/hp-hr) of particulate matter

The project will install a fire pump meeting these emission standards.

To comply with Subpart IIII, the emergency generator must meet the emission standards for new non-road CI engines (Tier 2 or 3). Engines with a model year 2006 or later with a power rating of 560 kW (750 hp) or greater must meet the following limits:

- 6.4 g/kW-hr (4.8 g/hp-hr) of VOC + NO_x
- 3.5 g/kW-hr (2.6 g/hp-hr) of CO
- 0.2 g/kW-hr (0.15 g/hp-hr) of particulate matter

The emergency generator associated with the proposed project will be certified to meet non-road emission standards.

3.4 State of the Art Air Pollution Control

SOTA is also referred to as "advances in the art of air pollution control" and may include "performance limits that are based on air pollution control technology, pollution prevention methods, and process modifications or substitutions that will provide the greatest emissions reductions that are technically and economically feasible." The NJDEP has developed technical SOTA manuals for various types of processes, including stationary combustion turbines, boilers, and engines. SOTA applicability thresholds for criteria pollutants are 5 tpy per unit for each pollutant, and non-criteria pollutants are also subject to SOTA on a pollutant-specific basis.

Non-criteria pollutant emissions from the combustion turbines are subject to SOTA requirements when pollutant-specific thresholds are exceeded. Appendix B provides a summary of the non-criteria pollutants and compares the annual potential to emit for each piece of equipment with the applicable threshold. Only ammonia exceeds the applicable SOTA threshold.

The project's SCR control system will use ammonia as the reagent to control NO_x emissions. A small amount of NH_3 will remain un-reacted through the catalyst, which is called the "ammonia slip." The NH_3 slip will be limited to 5.0 ppm_v at all load conditions and ambient temperatures. With an ammonia slip of only 5.0 ppm_v the project will be able to meet its stringent NO_x limit along with the 5.0 ppm_v prescribed ammonia SOTA limit for combined-cycle turbines with SCR. This limit is consistent with a recently issued NJDEP air permit for a combined cycle facility.

SOTA for criteria pollutants is described in Section 4.

NJAC 7:27-8.12(e) specifies that sources with pollutants meeting certain other standards also meet SOTA. For pollutants subject to LAER requirements, LAER is presumed to meet SOTA requirements. For pollutants subject to BACT requirements, BACT is presumed to meet SOTA requirements. For HAPs subject to MACT, compliance with MACT represents SOTA. For pollutants subject to NSPS, compliance with NSPS represents SOTA. Sources subject to SOTA may comply with the prescribed levels in the applicable manual or may conduct a case-by-case SOTA determination using a “top down” approach, similar to a BACT analysis.

3.5 Operating Permit

Subchapter 22 specifies that a facility with an annual potential to emit equal to or exceeding any of the following thresholds is required to obtain an Operating Permit from NJDEP.

- CO – 100 tpy;
- PM_{10} – 100 tpy;
- TSP – 100 tpy;
- SO_2 – 100 tpy;
- NO_x – 25 tpy;
- VOC – 25 tpy;
- Pb – 0.6 tpy;
- Any other contaminant, except carbon dioxide – 100 tpy;
- Any single hazardous air pollutant (HAP) – 10 tpy; and
- Combination of HAPs – 25 tpy.

Potential NO_x, CO and VOC emissions for the project exceed the Title V Operating Permit applicability threshold, triggering the need to apply for the Operating Permit. The project is also required to obtain an Operating Permit due to the combustion turbines being subject to New Source Performance Standards Subpart KKKK. Sources are required to submit their Operating Permit application within 12 months of a new facility commencing operation.

An Operating Permit application is a comprehensive document that includes potential to emit data for all sources across the facility; supporting information and calculations; control equipment data; a review of state and federal regulations; a description of proposed monitoring methods; fuel data; stack and vent information; a proposed compliance plan; proposed operating hours; and descriptions of normal source operation and startup and shutdown conditions for each source at the facility along with emissions data for those operating modes. The Operating Permit application must also include a SOTA determination for all equipment with emissions above pollutant-specific thresholds.

Table B of Subchapter 22 also lists pollutant-specific reporting thresholds for HAPs. Potential emissions of ammonia, acrolein, benzene, formaldehyde, and toluene exceed their reporting thresholds on a per turbine basis and, therefore, must meet the reporting requirements under Subchapter 21. In addition, the project must also demonstrate acceptable risk levels for these pollutants using NJDEP's risk screening worksheet or a more refined analysis. HAP emissions from the project will meet the NJDEP risk guideline values. A detailed discussion of the risk assessment results will be provided in the NEC Dispersion Modeling Report, which will be submitted under separate cover.

Permit applications are submitted using the RADIUS system. This application for a Permit to construct has been submitted using RADIUS. A major component of the application is a compliance plan, which is developed through the RADIUS submittal. This plan details how the project will demonstrate that the sources will not exceed emission limits imposed by state and federal regulations. The compliance plan also addresses records to be maintained at the facility, and the test methods to be used to demonstrate compliance. Finally, the plan will identify the schedule for submitting compliance certifications, usually performed on an annual basis. A printout of the RADIUS application, including the compliance plan is provided in Appendix A.

3.6 National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)

There are no 40 CFR Part 61 standards applicable to the proposed facility operations. Current USEPA AP-42 emission factors, other emission factors and vendor information were reviewed in determining if the proposed project was subject to a standard under 40 CFR Part 63. Based on potential emission calculations, the potential emissions of a single HAP will not exceed the major source threshold of 10 tpy. In addition, potential emissions of combined HAPs will be less than the major source threshold of 25 tpy. Therefore, the major source NESHAP standards under 40 CFR Part 63 are not applicable to this project.

The USEPA has also promulgated a variety of standards applicable to area sources, those sources that are not considered major HAPs. USEPA recently promulgated an area source standard for industrial, commercial and institutional boilers. This standard does not have requirements for boilers that are natural gas fired. As such, the boilers associated with the proposed project do not have any requirements under this standard.

3.7 Acid Rain Program

Title IV of the Clean Air Act Amendments required USEPA to establish a program to reduce emissions of acid rain forming pollutants, called the Acid Rain Program. The overall goal of this program is to achieve significant environmental benefits through reduction in SO_2 and NO_x emissions. To achieve this goal, the program employs both traditional and market-based approaches for controlling air pollution. Under the market-based aspect of the program, affected units are allocated SO_2 allowances by the USEPA, which may be used to offset emissions, or traded under the market allowance program. In addition, in order to ensure that facilities do not exceed their allowances, affected units are required to monitor and report their emissions using a CEMS system, as approved under 40 CFR Part 75.

The project is subject to the Acid Rain Program based on the provisions of 40 CFR 72.6(a)(3) because the turbines are considered utility units under the program definition and they do not meet the exemptions listed under paragraph (b) of this Section. The project will be required to submit an acid rain permit application at least 24 months prior to the date on which the affected unit commences operation. NEC will submit an acid rain permit application in compliance with these requirements prior to this deadline.

3.8 Cross-State Air Pollution Rule

On March 10, 2005, USEPA issued the Clean Air Interstate Rule (CAIR) which requires reductions in emissions of NO_x and SO_2 from large fossil fueled electric generating units using a cap and trade system. The rule provides both annual emissions budgets and an ozone season emission budget for each state. On July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit issued an opinion vacating and remanding these rules. However, on December 23, 2008, the Court granted rehearing only to the extent that it remanded the rules to USEPA without vacating them. The December 23, 2008 ruling leaves CAIR in place until the USEPA issues a new rule to replace CAIR in accordance with the July 11, 2008 provisions. On July 6, 2011, the USEPA issued the Cross-State Air Pollution Rule (CSAPR) which replaces CAIR. New Jersey power generation sources of 25 MW or greater are subject to this rule. Under this new rule, New Jersey is still required to implement provisions for annual NO_x and SO_2 emissions and ozone season NO_x emissions. Under this cap-and-trade program, assets holding excess allowances will be able to sell or trade allowances to those without sufficient allowances. The number of allowances will gradually decrease, encouraging the retrofit of additional NO_x and SO_2 controls on sources; thereby reducing regional emissions and encouraging the development of cleaner sources of electricity. The first year for implementation of this rule is 2012. The USEPA has developed a distribution of allowances for existing facilities regulated under this program. These allowances are generally less than those provided under CAIR. The USEPA has also provided new unit set asides for each state. New sources will continue to have these allowances provided until the facility is able to establish a baseline of operations. States will have an opportunity to re-evaluate the distribution of allowances as they incorporate CSAPR into their State Implementation Plan (SIP). But, this will not occur before 2013. It is anticipated that New Jersey will have revised its SIP, and incorporated rules to implement CSAPR prior to operation of the proposed project. The project will comply with the rules currently in effect at the time of operational start.

3.9 Regional Greenhouse Gas Initiative

New Jersey has signed the Regional Greenhouse Gas Initiative (RGGI) Memorandum of Understanding (MOU). RGGI applies to all electric generating units greater than 25 MW. RGGI will stabilize carbon dioxide (CO_2) emissions from the power sector at approximately current levels from the start of the program in 2009 through the beginning of 2015. From 2015 through 2018, the emissions cap will decline, achieving a 10 percent reduction by 2019. In addition, some of the program reductions will be achieved outside the power sector through emissions offset projects.

New Jersey regulations for the CO_2 Budget Trading Program are codified under N.J.A.C 7:27C. The CO_2 Budget Trading Program is a mandatory cap-and-trade program. Under the CO_2 budget program, sources are required to acquire, from auctions or directly from NJDEP, one allowance for every ton of CO_2 that they emit. The proposed project will acquire CO_2 allowances in compliance with this regulation.

4. CONTROL TECHNOLOGY EVALUATION – SOTA/BACT/LAER

Pre-construction review for new major stationary sources involves an evaluation of LAER for NNSR sources, BACT for PSD sources, and SOTA for other pollutants with potential emissions greater than 5 tpy per unit. A control technology analysis has been performed for the proposed facility based upon the USEPA guidance document New Source Review Workshop Manual (USEPA, 1990). The SOTA evaluations have been performed in accordance with NJAC 7:27-8.12 and NJDEP's SOTA Manual (NJDEP, 1997). The PSD and NNSR requirements for each pollutant were defined in Section 3.0 of this application, and are briefly summarized in the sections below.

4.1 Regulatory Applicability of Control Requirements

This section provides a brief summary of the control technology requirements under the NNSR, PSD, and SOTA programs for each pollutant. Control technology requirements are generally based on the potential emissions from the new or modified source and the attainment status of the area in which the source is located. A detailed determination of applicable regulatory requirements under PSD and NNSR rules are provided in Section 3.0. The following sections discuss the applicability of LAER, BACT and SOTA requirements for emissions from the equipment associated with the project.

4.1.1 NNSR Pollutants Subject to LAER

Pollutants subject to NNSR are required to implement LAER. As indicated in Table 1-1, potential emissions of NO_x and VOC exceed major source thresholds, and are therefore subject to NNSR and LAER requirements.

Essex County is also in nonattainment of the 24-hour and annual standards for $PM_{2.5}$. Under NJDEP's *Revised Interim Permitting and Modeling Procedures for New or Modified Sources Emitting between less than 100 Tons per Year of* $PM_{2.5}$ *(Fine Particulate) and Proposing between a 10 – 99 ton per year increase in PM2.5* (December 14, 2010), LAER is not required for $PM_{2.5}$ when modeling demonstrates the project's impacts to be below SILs at all receptors. The modeling analysis for $PM_{2.5}$ is provided in the NEC Dispersion Modeling Report.

4.1.2 PSD Pollutants Subject to BACT

Pollutants subject to PSD review are subject to a BACT analysis. The proposed Project is considered a major source for PSD purposes since potential emissions exceed major source thresholds. Therefore, individual pollutants are subject to BACT requirements if their potential emissions exceed the significant emission rates presented in Table 1-1. As shown in this table, the project is subject to PSD review for NO_2, CO, and PM_{10}, and is therefore required to implement BACT for these pollutants. Since the area is designated as nonattainment for ozone, NO_2 emissions are subject to BACT as well as LAER. However, since LAER requirements are at least as stringent as BACT, the LAER analysis for NO_x will also satisfy the BACT requirements for NO_2. VOC emissions, while below the PSD threshold and would not otherwise be subject to BACT, are subject to NNSR and, therefore, the more stringent LAER will apply for VOC.

4.1.3 Pollutants Subject to SOTA

SOTA is also referred to as "advances in the art of air pollution control" and may include "performance limits that are based on air pollution control technology, pollution prevention methods, and process modifications or substitutions that will provide the greatest emissions reductions that are technically and economically feasible." The NJDEP has developed technical SOTA manuals for various types of processes, including stationary combustion turbines, boilers, and engines. SOTA applicability thresholds for criteria pollutants are 5 tpy per unit for each pollutant, and non-criteria pollutants are also subject to SOTA on a pollutant-specific basis. As described in Section 3.4, the only non-criteria pollutant emissions from the project that exceeds these thresholds is ammonia. As such, pollutants subject to SOTA for the project include NO_x, VOC, CO, TSP, PM_{10}, $PM_{2.5}$, SO_2, and NH_3.

NJAC 7:27-8.12(e) specifies that sources with pollutants meeting certain other standards also meet SOTA. For pollutants subject to LAER requirements, compliance with LAER meets SOTA requirements. For pollutants subject to BACT requirements, compliance with BACT meets SOTA requirements. For HAPs subject to MACT, compliance with MACT meets SOTA requirements. For pollutants subject to NSPS, compliance with NSPS represents SOTA. Sources subject to SOTA may comply with the prescribed levels in the applicable manual or may conduct a case-by-case SOTA determination using a "top down" approach, similar to a BACT analysis.

4.1.4 Emission Units Subject to LAER and BACT Analyses

For a facility subject to a BACT or LAER analysis, each pollutant emitted in amounts greater than the regulatory thresholds are subject to a prescribed level of control technology review for each emission unit that emits that pollutant. For the proposed project, the source responsible for the majority of the project's emissions will be the combined cycle combustion turbines with supplemental duct burning. Therefore, the primary focus of the BACT and LAER analyses presented in the following sections is on the combined cycle combustion turbines. Evaluation of the ancillary equipment is conducted based on NJDEP guidance and consistent with proposed small annual emission levels and with limited hours of operation.

4.2 LAER and BACT Analysis Approach

The sections below outline the approach used to conduct the LAER and BACT analyses presented in this application.

4.2.1 Lowest Achievable Emission Rate

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).

In no event should application of LAER permit a new source or modification to emit any air contaminant in excess of the amount permitted under any applicable emission standard under NJAC 7:27 or 40 CFR. NJDEP may consider any new information, including recent permit decisions, or public comments received.

To determine the most stringent emission limitation as defined above, several sources were utilized including recently issued preconstruction permits for other sources, USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database, and individual state agency databases.

LAER is expressed as an emission rate and may be achieved from one, or a combination of, the following:

- Change in raw material processes, which are typically considered for industrial processes that use chemicals such as solvents, where substitution to a lower emitting chemical may be technically feasible. For the project, the "raw material" would be the type of fuel combusted in the combustion turbines. The primary fuel for the project is natural gas, which results in the lowest uncontrolled NO_x and VOC emissions.

- Process modifications, which are typically considered for industrial processes that use chemicals, where a change in the process methods or conditions may result in lower emissions. For the project, the “process” is the combustion turbine. The proposed F-Class turbines will utilize efficient combustion technology to reduce the formation of NO_x and VOC emissions as combustion byproducts.
- Add-on controls, which capture and control air pollutant emissions using additional add-on equipment such as SCR or catalytic oxidation. Add-on control is a common option for combustion turbines. Both SCR and oxidation catalysts have been used for combined cycle turbine installations, and are proposed for the project.

The analyses presented below for NO_x and VOC follow the guidelines presented above.

4.2.2 Best Available Control Technology

BACT is defined as the optimum level of control applied to a 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, as necessary, in addition to the benefit of reduced emissions that each technology would provide. The BACT analyses presented in the following sections consist of up to four steps as outlined below.

4.2.2.1 Identification of Technically Feasible Control Options

The first step in a BACT analysis is the identification of technically feasible and available control technology options, including consideration of transferable and innovative control measures that may not have been previously 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, such as RACT or NJDEP 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 most stringent alternative is proposed, then no further analysis is required. 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 USEPA's RBLC database was performed. Individual searches were performed for each pollutant emitted from each emission unit. The most recently issued permits from New Jersey and other permits listed on the RBLC were also analyzed if available. Information was found for several hundred large combined cycle power plant projects permitted in the past decade. Appendix C provides a summary of recent similar energy projects from around the country. Less recent projects were also included due to regional proximity and/or very stringent emission limits. Using these criteria, lists for each pollutant for each equipment source were compiled and are presented in Appendix C.

If two or more technically feasible options are identified, the next three steps (as presented below) are applied to identify and compare the economic, energy and environmental impacts of the options.

4.2.2.2 Economic (Cost-Effectiveness) Analysis

This analysis consists of an estimation of cost and calculation of the cost-effectiveness of each control technology, on a dollar per ton of pollution removed basis. Annual emissions with a control 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 allowed with BACT considerations (such as an NSPS or RACT limit). Annual costs are calculated by adding annual operation and maintenance costs to the annualized capital cost of a control option. Cost-effectiveness (dollars per ton) of a control option is the annual cost (dollars per year) divided by the annual reduction in emissions (tpy). If either the most effective control option is proposed, or if there are no technically feasible control options, an economic analysis is not required.

4.2.2.3 Energy Impact Analysis

Two types of energy impacts are normally considered quantifiable. First, when the installation of a particular option would result in a reduction in either the power output capacity or reliability of a unit, this reduction is a quantifiable energy impact. Second, the consumption of energy by the control option itself is a quantifiable energy impact. These impacts can be quantified by either an increase in fuel consumption due to reduced efficiency or fuel consumption to power the equipment.

4.2.2.4 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 be identified. Non-air related impacts such as solid waste generation, increased water consumption or waste water generation may also be an issue associated with a control option. These additional impacts should be identified and qualitatively or quantitatively evaluated.

4.3 LAER/BACT/SOTA Analysis for NO_x

NO_x is formed during the combustion of fuel and is generally classified as either thermal NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric nitrogen is oxidized at high temperatures to produce nitrogen oxide (NO), NO_2, and other oxides of nitrogen. The major factors influencing the formation of thermal NO_x are temperature, concentrations of oxygen in the inlet air and residence time within the combustion zone. Fuel-related NO_x is formed from the oxidation of chemically bound nitrogen in the fuel. Fuel-related NO_x is generally minimal for natural gas combustion. As such, NO_x formation from combustion of natural gas is due mostly to thermal NO_x formation.

Reduction in NO_x formation can be achieved using combustion controls and/or flue gas treatment. Available combustion controls include water or steam injection and low emission combustors. Typical gas turbines are designed to operate at a nearly stoichiometric ratio of fuel in the combustion zone, with additional air introduced downstream. Fuel-to-air ratios below stoichiometric are referred to as fuel-lean mixtures. This type of fuel mixture limits the formation of NO_x because there is lower flame temperature with a lean fuel mixture. Using this concept, lean combustors are designed to operate below the stoichiometric ratio, thereby reducing the thermal NO_x formation within the combustion chamber.

The F-Class turbines proposed for the project utilize a lean fuel technology. In addition, exhaust gases from the turbine (and duct burner) will exhaust through an SCR system (discussed below) to further reduce NO_x emissions to 2.0 ppm_v at 15 percent O_2, with and without duct burning.

The project will also utilize an auxiliary boiler. The auxiliary boiler will utilize flue gas recirculation and low-NO_x burner technology, two combustion optimization techniques that also reduce the formation of NO_x. Using these enhanced combustion techniques, emissions from the auxiliary boiler will be limited to 0.02 lb/MMBtu.

The following discussion will demonstrate that the proposed NO_x emission rates for the combined cycle turbines and auxiliary boiler are considered LAER. As mentioned previously, since LAER requirements are at least as stringent as BACT and SOTA, the LAER analysis for NO_x will also satisfy the BACT and SOTA requirements for NO_2 and NO_x.

4.3.1 Identification of Control Options

SCR is an add-on NO_x control technology that is placed in the exhaust stream following the gas turbine/duct burner. SCR involves the injection of ammonia into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with the NO_x contained within the flue gas to form nitrogen gas and water in accordance with the following chemical reactions:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

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 homogeneous material that forms both the active surface and the substrate. NH_3 is fed and mixed into the combustion gas upstream of the catalyst bed in greater than stoichiometric amounts to achieve maximum conversion of NO_x. Excess NH_3 which is not reacted in the catalyst bed is subsequently emitted through the stack; this is called "ammonia slip."

An important factor that affects the performance of an SCR system is the operating temperature. The optimal temperature range for standard base metal catalysts is between 400°F and 800°F. Because the optimal temperature is below the CTG exhaust temperature but above the stack exhaust temperature, the catalyst needs to be located within the HRSG.

An undesirable side effect of the use of SCR systems is the potential for formation of ammonium bisulfate and ammonium sulfate, referred to as ammonium salts. These salts are reaction products of SO_3 and NH_3. Ammonium salts are corrosive and can stick to the heat exchanger surfaces, duct work or the stack at low temperatures. In addition, ammonia salts are considered $PM_{10}/PM_{2.5}$, and therefore increase the emissions of these criteria pollutants. Use of low sulfur fuels such as natural gas minimizes the formation of SO_3 and the subsequent formation of these ammonium salts.

4.3.2 Search of LAER/BACT Determinations

4.3.2.1 Combustion Turbine Generators and Duct Burners

The search of the RBLC and other available permits identified several natural gas fired combined cycle combustion turbine projects. As described previously, representative projects were selected based upon recent decisions, local proximity, or stringent limits. Details for representative facilities are presented in Appendix C. The lowest permitted NO_x limit for a natural gas fired combined cycle turbine with duct burning was 2.0 ppm_v at 15% O_2. Of the representative projects at least eight had NO_x LAER determinations greater than or equal to 2.0 ppm_v at 15% $O_{2.}$ All of these projects use SCR systems in combination with combustion optimization technology such as low-NO_x burners. It is our understanding that several of these projects have demonstrated compliance with the 2.0 ppm_v emission limits under primary operating modes. Some of these projects have permit limits above 2.0 ppm_v to accommodate alternative operating modes such as duct burning.

In general, LAER determinations have focused on the level that can be achieved in the primary operating mode (typically gas-fired 100 percent load), with NO_x levels being set for alternative modes (duct burning, partial load, etc.) at the levels that result from application of the same degree of control used to achieve LAER in the primary mode.

4.3.2.2 Auxiliary Boiler

The RBLC and recent air permit search for natural gas-fired boilers between 10 and 100 MMBtu/hr in size identified close to 100 installations. NO_x emission limits for these boilers widely range from approximately 0.009 lb/MMBtu to 0.08 lb/MMBtu. Details on approximately 40 of the installations that were determined to be most representative for the proposed boiler are provided in Appendix C. The projects with emission limits less than 0.011 lb/MMBtu are generally industrial/commercial boilers less than 30 MMBtu/hr that are operated continuously to support industrial processes or other operations; these were not considered relevant to the project. Beyond these projects, other determinations generally proposed NO_x emission limits greater than 0.03 lb/MMBtu. The most recent determination for an auxiliary boiler in New Jersey proposed a NO_x emission limit of 0.037 lb/MMBtu.

4.3.3 LAER/BACT Determinations

4.3.3.1 Combustion Turbine Generators and Duct Burners

NEC is proposing a NO_x emission limit of 2.0 ppm_v at 15 percent O_2 (with and without duct burning) as LAER for the proposed project. This level of emissions will be achieved through the application of DLN burners in combination with SCR. This emission level is consistent with the most stringent level of control found during the RBLC search and has been demonstrated in practice.

4.3.3.2 Auxiliary Boiler

NEC is proposing a NO_x emission limit of 0.02 lb/MMBtu. The auxiliary boiler will use flue gas recirculation in combination with low-NO_x burners. These technologies, used in combination, are capable of reducing NO_x emissions by 60 to 90 percent. This limit is consistent with NJDEP SOTA guidance, the results from the RBLC database search and a recent project in New Jersey.

4.4 LAER/SOTA Analysis for VOC

Combustion turbines have inherently low VOC emission rates. Emissions of VOC from a combustion turbine occur as a result of 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 CO_2 and water. VOC emissions can be minimized by the use of good combustion controls and add-on controls as described below.

The F-Class turbines proposed for the project will utilize good combustion controls and exhaust through an oxidation catalyst to further reduce VOC emissions. Emissions of VOC from the exhaust stack will be limited to 1.0 ppm_v at 15 percent O_2 without duct burning and 2.0 ppm_v with duct burning.

The project will also utilize an auxiliary boiler. The auxiliary boiler will utilize combustion optimization technologies to minimize incomplete combustion and subsequent emissions of VOC. Using good combustion controls, emissions from the auxiliary boiler will be limited to 0.005 lb/MMBtu.

The following discussion demonstrates that the proposed VOC emission rates for the combined cycle turbines and auxiliary boiler are considered LAER. As mentioned previously, since LAER requirements are at least as stringent as SOTA requirements, application of LAER technology for VOC will also satisfy the SOTA requirements for VOC. BACT analysis is not required for VOC emissions as the project's VOC emissions will be below the PSD significant threshold for VOC.

4.4.1 Identification of Control Options

There are only two practical methods for controlling VOC emissions from combustion processes: efficient combustion and add-on control equipment. The most stringent level of control is through the use of add-on control equipment. The only post-combustion control that can be practically implemented is catalytic oxidation. Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. The optimal location for VOC control, in the 900°F to 1,100°F temperature 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 SO_2 to SO_3. As described previously, SO_3 may react with water and/or NH_3 to form H_2SO_4 and/or ammonium salt (PM_{10}/$PM_{2.5}$). Therefore, the placement of the oxidation catalyst in the "cooler" section of the HRSG, which is necessary for CO control, is the optimal design.

VOC emissions from the auxiliary boiler will also occur due to incomplete combustion. As such, VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times, and turbulent mixing of fuel and combustion air. In practice, post-combustion control methods are not routinely implemented for the reduction of VOC emissions from auxiliary boilers, as supported by the search of the BACT/LAER determinations presented below.

4.4.2 Search of LAER/BACT Determinations

4.4.2.1 Combustion Turbine Generators and Duct Burners

The search of the RBLC and other available permits identified many natural gas-fired combined cycle combustion turbine projects. Details for approximately 30 of these facilities have been included in Appendix C. Based on this search, use of an oxidation catalyst appears to be the most stringent level of VOC control for natural gas fired combined cycle turbines. VOC limits range from 0.7 ppm_v to 6 ppm_v, with most projects demonstrating LAER between 1 ppm_v and 2 ppm_v. The lowest VOC limit found in a permit for a natural gas fired combined cycle turbine was 0.7 ppm_v without duct burning, which was issued in to CPV Warren LLC in Virginia. While this facility has been permitted, it has not been constructed and has not demonstrated compliance with this limit. The most recent VOC LAER determination in the RBLC was a permit for West Deptford Energy in New Jersey issued in May 2009 and updated in January 2011. The VOC limit proposed in this draft permit was 1.9 ppm_v. An oxidation catalyst and good combustion control were proposed as LAER for both the Empire Generating Project and the West Deptford Energy Project. This is consistent with other recent projects in the RBLC which have VOC limits ranging from 1.0 ppm_v to 5.0 ppm_v and propose an oxidation catalyst as LAER. The variation in VOC concentrations between different projects is not unexpected due to differences in turbine and HRSG manufacturers and overall engineering design. Based on the review of the RBLC, LAER for VOC is utilization of an oxidation catalyst system to achieve an outlet VOC concentration in the 1-2 ppm_v range.

In general, LAER determinations have focused on the level that can be achieved in the primary operating mode (typically gas fired 100 percent load), with VOC levels being set for alternative modes (duct burning, partial load, etc.) at the levels that result from application of the same degree of control used to achieve LAER in the primary mode.

4.4.2.2 Auxiliary Boiler

The RBLC and recent air permit search for natural gas fired boilers between 10 and 100 MMBtu/hr in size identified close to 100 installations. VOC emission limits for these installations range from approximately 0.002 lb/MMBtu to 0.08 lb/MMBtu. Details on approximately 30 of the installations that were determined to be most applicable to the proposed boiler are provided in Appendix C.

The most recent determination in the database is for a commercial boiler with a VOC BACT limit of 0.0054 lb/MMBtu. Most of the boilers that operate in a similar manner to the proposed boiler also have operational restrictions on hours. There are several determinations for auxiliary boilers at energy generating facilities in the database. The most recent LAER limit for an auxiliary boiler is 0.002 lb/MMBtu for CPV Warren. However, this project has not been constructed and this limit has not been demonstrated in practice. The most stringent emission limit for an operating auxiliary boiler is 0.004 lb/MMBtu. There are only two facilities currently operating with this limit. The remainder of the installations have emission limits of 0.005 lb/MMBtu or greater. Based on the review of the RBLC, LAER for VOC is good combustion practices to achieve a VOC emission limit in the 0.004 to 0.005 lb/MMBtu range.

4.4.3 LAER Determinations

4.4.3.1 Combustion Turbine Generators and Duct Burners

NEC is proposing a VOC emission limit of 1.0 ppm_v at 15 percent O_2 without duct burning and 2.0 ppm_v at 15 percent O_2 while duct burning as LAER for the proposed project. This level of emissions will be achieved via good combustion control and an oxidation catalyst. This emission level is consistent with the limits and control technologies found in the RBLC for recent LAER determinations in New Jersey and in other states.

4.4.3.2 Auxiliary Boiler

NEC is proposing a VOC emission limit of 0.005 lb/MMBtu from the auxiliary boiler using good combustion practices in combination with reduced annual operating hours. This is consistent other LAER determinations for this type of equipment.

4.5 BACT/SOTA Analysis for CO

Emissions of CO from combustion occur as a result of incomplete combustion of fuel. CO emissions are minimized by the use of proper combustor design, good combustion practices and add-on controls. The combined cycle turbines and the auxiliary boiler will be sources of CO emissions. Since the potential emissions from the project exceed PSD significance thresholds, BACT is required for CO emissions. As indicated previously, pollutants that comply with BACT meet SOTA requirements.

The F-Class turbines proposed for the project will utilize good combustion controls and exhaust through an oxidation catalyst to reduce CO emissions. Emissions of CO from the exhaust stack will be limited to 2.0 ppm_v at 15 percent O_2 with and without duct burning.

The auxiliary boiler will utilize good combustion practices to minimize incomplete combustion and subsequent emissions of CO. Using good combustion controls, emissions from the auxiliary boiler will be limited to 0.037 lb/MMBtu.

The following discussion demonstrates that the proposed CO emission rates for the combined cycle turbines and auxiliary boiler are considered BACT.

4.5.1 Identification of Control Options

There are only two practical methods for controlling CO emissions from combustion processes: efficient combustion and add-on control equipment. The most stringent level of control is the use of add-on equipment. The only post-combustion control that can be practically implemented is catalytic oxidation. Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. CO reduction efficiencies in the range of 80 to 90 percent can be expected, although CO reduction may at times be less than these values due to the low inlet concentrations expected from the F-Class turbines.

CO emissions from the auxiliary boiler will also occur due to incomplete combustion. As such, combustion design that promotes high combustion temperatures, long residence times, and turbulent mixing of fuel and combustion air is the common practice used to minimize CO emissions. Although it is technologically feasible to control CO emissions from a boiler in the 10 to 100 MMBtu/hr size range using an oxidation catalyst, current combustion technology results in very low emissions of CO such that add-on control would not be considered cost-effective.

4.5.2 Search of LAER/BACT Determinations

4.5.2.1 Combustion Turbine Generators and Duct Burners

The search of the RBLC other available permits identified close to 300 natural gas fired combined cycle combustion turbine projects. Based on this search, use of an oxidation catalyst appears to be the most stringent level of control for natural gas fired combined cycle turbines.

CO emission limits from recently permitted projects generally ranged from 0.9 ppm_v to 15 ppm_v (or greater). The lowest CO limit found in a permit for a natural gas fired combined cycle turbine was 0.9 ppm_v without duct burning and 1.8 ppm_v with duct burning, issued to Kleen Energy Systems in Connecticut. While the duct burning limit is consistent with other determinations, the 0.9 ppm_v limit is an outlier. This is the only facility that proposed this limit, and while this facility has been permitted, it has not been constructed and thus has not demonstrated compliance with this limit. As such, 0.9 ppm_v is not considered to represent BACT. A search of the RBLC indicates that the CPV Warren facility in Virginia also proposed a CO emission limit less than 2.0 ppm_v. The CPV Warren facility has not been constructed. There are many facilities in the RBLC with recently permitted BACT CO emission limits of 2.0 ppm_v (or greater). For example, the Empire Generating and

Caithness Long Island Energy projects in New York State have permit limits of 2.0 ppm$_v$ for CO, which is considered representative of BACT. It is our understanding that several of these facilities are operating in compliance with their 2.0 ppm$_v$ limit.

4.5.2.2 Auxiliary Boiler

The RBLC and recent air permit search for natural gas-fired boilers between 10 and 100 MMBtu/hr in size identified close to 100 installations. CO emission limits for these installations range from approximately 0.0073 lb/MMBtu to 0.08 lb/MMBtu. Details on approximately 30 of the installations that were determined to be most applicable to the proposed boiler are provided in Appendix C.

The most stringent limit for an auxiliary boiler at an energy generating facility is 0.0164 lb/MMBtu at Emery Generating Station in Iowa, which was permitted in 2002. This installation is operational and it utilizes a catalytic oxidizer with an estimated control efficiency of 80 percent to achieve this emission rate. Since this installation, there have been many projects permitted without add-on controls that utilize good combustion practices to achieve CO control. The most recent auxiliary boiler installation listed in the RBLC has a CO limit of 0.15 lb/MMBtu. The most recent SOTA demonstration for a project in New Jersey has a CO limit of 0.036 lb/MMBtu. There are several other recent determinations with CO limits between 0.02 and 0.04 lb/MMBtu. These installations also utilize good combustion practices to control CO emissions.

4.5.3 LAER/BACT Determinations

4.5.3.1 Combustion Turbine Generators and Duct Burners

NEC is proposing a CO emission limit of 2.0 ppm$_v$ at 15 percent O_2 with and without duct burning as BACT for the proposed project. This level of emissions will be achieved via good combustion control and an oxidation catalyst. This proposal is consistent with the limits and control technologies found in the RBLC and with recent BACT determinations in New Jersey and in other states.

4.5.3.2 Auxiliary Boiler

NEC is proposing a CO emission limit of 0.037 lb/MMBtu from the auxiliary boiler using good combustion practices in combination with reduced annual operating hours. This is consistent with NJDEP SOTA guidance and other BACT determinations for this type of equipment.

4.6 BACT/SOTA Analysis for Particulate Matter (PM_{10}/$PM_{2.5}$)

Emissions of particulate matter from combustion occur as a result of inert solids contained in the fuel, unburned fuel hydrocarbons which agglomerate to form particles, and mineral matter in water that may be injected for NO_x control during diesel firing. Particulate emissions can also result from the formation of ammonium sulfates due to the conversion of SO_2 to SO_3, which is then available to react with ammonia to form ammonium sulfate. All of the particulate matter emitted from the turbines is conservatively assumed to be less than 2.5 microns in diameter. Therefore, PM_{10} and $PM_{2.5}$ emission rates are assumed to be the same.

The combustion of clean burning fuels is the most effective means for controlling particulate emissions from combustion equipment. The project is proposing to use natural gas as the only fuel for the turbines. Natural gas is a very clean burning fuel with very low associated particulate emissions. NEC is not aware of any combustion turbine projects in existence that have add-on particulate control.

The F-Class turbines proposed for the project will utilize natural gas as their only fuel to minimize particulate emissions. Emissions of PM_{10}/$PM_{2.5}$ from the exhaust stack will be limited to 0.0057 lb/MMBtu without duct burning and 0.0064 lb/MMBtu with duct burning.

The project will also utilize an auxiliary boiler. The auxiliary boiler will combust only natural gas, resulting in a PM_{10}/$PM_{2.5}$ emission limit of 0.01 lb/MMBtu. The wet cooling tower will also be a source of PM_{10}/$PM_{2.5}$ emissions. The project is proposing use of a high efficiency drift eliminator (0.0005%).

The following discussion will demonstrate that the proposed PM_{10}/$PM_{2.5}$ emission rates for the combined cycle turbines and auxiliary boiler are considered BACT.

4.6.1 Search of LAER/BACT Determinations

4.6.1.1 Combustion Turbine Generators and Duct Burners

The search of the RBLC and other available permits identified over 300 natural gas fired combined cycle combustion turbine projects. Based on this search, use of clean burning fuels is the primary control for particulate emissions. Particulate matter emission limits in the RBLC database generally ranged from approximately 0.003 lb/MMBtu to 0.3 lb/MMBtu (or greater). The lowest PM_{10}/$PM_{2.5}$ limit found in a permit for an F-series natural gas fired combined cycle turbine was 0.0051 lb/MMBtu, which was issued to Kleen Energy Systems in Connecticut. While this facility has been permitted, it has not been constructed and has not demonstrated compliance with this limit. Similarly, Caithness Long Island Energy has a limit of 0.0055 lb/MMBtu. Beyond these examples, there are many facilities in the RBLC with permitted BACT $PM_{10}/PM_{2.5}$ emission limits in the range of 0.006 lb/MMBtu to 0.01 lb/MMBtu. Generally, all of these projects utilize clean burning fuel as their primary control technology and their emission limits are based upon the overall quality of their commercial natural gas source.

4.6.1.2 Auxiliary Boiler

A review of the RBLC indicates that good combustion practices and clean burning fuels have typically been determined to be BACT for boilers. $PM_{10}/PM_{2.5}$ emission limits for natural gas fired boilers vary widely, ranging from 0.002 lb/MMBtu through 0.6 lb/MMBtu. $PM_{10}/PM_{2.5}$ emission limits for gas-fired auxiliary boilers of similar size are as low as 0.003 lb/MMBtu. The most recent listing in the RBLC for an auxiliary boiler proposed a $PM_{10}/PM_{2.5}$ limit of 0.005 lb/MMBtu.

4.6.1.3 Wet Cooling Tower

A review of the RBLC provides very few entries for wet cooling towers, the most recent being in 2005. The NDJEP does not provide guidance on SOTA from wet cooling towers. However, in a recent New Jersey air permit for a combined cycle facility, BACT for PM_{10} and SOTA for $PM_{2.5}$ was determined to be utilization of a high efficiency drift eliminator with a removal efficiency of 0.0005 percent. This is the most effective drift eliminator commercially available.

4.6.2 BACT/SOTA Determinations

4.6.2.1 Combustion Turbine Generators and Duct Burners

NEC is proposing a $PM_{10}/PM_{2.5}$ emission limit of 0.0057 lb/MMBtu without duct burning and 0.0064 lb/MMBtu with duct burning as BACT for the proposed project. This level of emissions will be achieved by combusting only commercially available, pipeline quality natural gas in the turbines. This emission level is consistent with the limits and control technologies found in the RBLC for recent BACT determinations in New Jersey and in other states.

4.6.2.2 Auxiliary Boiler

NEC is proposing the exclusive use of clean-burning pipeline quality natural gas in conjunction with good combustion practices as BACT for the auxiliary boiler. The project proposes a $PM_{10}/PM_{2.5}$ emission limit of 0.01 lb/MMBtu boiler using natural gas as the only fuel in conjunction with reduced annual operating hours. This is consistent with other BACT determinations for this type of equipment.

4.6.2.3 Wet Cooling Tower

NEC is proposing use of a 0.0005 percent high efficiency drift eliminator as BACT and SOTA for PM_{10} and $PM_{2.5}$. This equates to hourly emission rates of 1.26 lb/hr and 0.57 lb/hr of PM_{10} and $PM_{2.5}$, respectively. Use of high efficiency drift eliminators is consistent with recent BACT and SOTA determinations in New Jersey and in other states.

4.7 SOTA Analysis for Sulfur Dioxide

Emissions of SO_2 are formed from the oxidation of sulfur in the fuel. SO_2 emissions can be controlled using pre- and post-combustion controls. Pre-combustion controls involve the use of low sulfur fuels such as natural gas or ULSD. Post-combustion controls involve the use of add-on control technology such as wet and dry flue gas desulfurization (FGD) processes. Installation of such systems is an established technology principally on coal-fired and high sulfur oil-fired steam electric generation stations. However, FGD systems are not practical for combustion turbines due to several factors including the large exhaust flow (and corresponding pressure drop) and the low inlet concentration in the flue gas. The use of natural gas and ULSD are the most common methods for controlling SO_2 emissions from combustion turbines.

The F-Class turbines proposed for the project will utilize natural gas as their only fuel to minimize SO_2 emissions. Emissions of SO_2 from the exhaust stack will be limited to 0.00037 lb/MMBtu with and without duct burning.

The project will also utilize an auxiliary boiler. The auxiliary boiler will combust only natural gas, resulting in an SO_2 emission limit of 0.0005 lb/MMBtu.

The following discussion will demonstrate that the proposed SO_2 emission rates for the combined cycle turbines and auxiliary boiler are considered BACT.

4.7.1 Search of LAER/BACT Determinations

4.7.1.1 Combustion Turbine Generators and Duct Burners

The search of the RBLC and other available permits identified close to 300 natural gas fired combined cycle combustion turbine projects. Based on this search, use of low sulfur fuels is the primary control for SO_2 emissions, with emission limits being dependent upon the sulfur content of the fuel and engine design. SO_2 emission limits in the RBLC generally ranged from 0.0003 lb/MMBtu to 0.01 lb/MMBtu (or greater). Most projects proposed limits in the range of 0.002 to 0.005 lb/MMBtu and utilized commercially available pipeline quality natural gas.

4.7.1.2 Auxiliary Boiler

A review of the RBLC indicates that combustion of clean burning low-sulfur fuels has typically been determined to be BACT for SO_2. The most stringent SO_2 emission limit for an auxiliary boiler found the RBLC was 0.0006 lb/MMBtu. The most recent project listed in the RBLC proposes an SO_2 emission limit of 0.0009 lb/MMBtu. Both limits are based upon the sulfur content of the natural gas supply.

4.7.2 LAER/BACT Determinations

4.7.2.1 Combustion Turbine Generators and Duct Burners

NEC is proposing a SO_2 emission limit of 0.00037 lb/MMBtu (with and without duct burning) as SOTA for the proposed project. This level of emissions will be achieved by combusting commercially available, pipeline quality natural gas with a maximum sulfur content of 0.17 grains per 100 standard cubic foot (scf) by weight in the combustion turbines. This emission level is consistent with the limits and control technologies found in the RBLC.

4.7.2.2 Auxiliary Boiler

NEC is proposing a SO_2 emission limit of 0.0005 lb/MMBtu as SOTA for the proposed project. This is consistent with other BACT determinations for this type of equipment.

4.8 BACT Analysis for Greenhouse Gases

The principal GHGs associated with the project are CO_2, methane (CH_4), and nitrous oxide (N_2O). Because these gases differ in their ability to trap heat, one ton of CO_2 in the atmosphere has a different effect on warming than one ton of CH_4 or one ton of N_2O. For example, CH_4 and N_2O have 21 times and 298 times the global warming potential of CO_2, respectively. GHG emissions from the proposed project are primarily attributable to combustion of fuels. The project will not have any other industrial processes releasing GHGs. By far the greatest proportion of potential GHGs emissions are from CO_2. Trace amounts of CH_4 and N_2O, would be emitted in varying quantities depending on operating conditions. However, emissions of CH_4 and N_2O are negligible when compared to total CO_2 emissions, and would not be considered significant to climate change issues. In addition, as presented previously, the project is proposing to implement LAER for both VOC (expressed as CH_4) and NO_x, such that these pollutants are being effectively controlled. As such, the remainder of this section will focus on BACT for CO_2.

CO_2 is a product of combusting any carbon containing fuel, including natural gas. All fossil fuel contains significant amounts of carbon. During complete combustion, the fuel carbon is oxidized into CO_2 via the following reaction:

$$C + O_2 \rightarrow CO_2$$

Full oxidation of carbon in fuel is desirable because CO, a product of partial combustion, has long been a regulated pollutant and because full combustion results in more useful energy. In fact, emission control technologies required for CO emissions (oxidation catalysts) increase CO_2 emission by oxidizing CO to CO_2.

There are limited alternatives available for controlling CO_2. The USEPA has indicated in the document, *PSD and Title V Permitting Guidance for Greenhouse Gases,* that carbon capture and sequestration (CCS) should be considered in BACT analyses as a technically feasible add-on control option for CO_2. Currently, there are no combined cycle power plants utilizing CCS, and although theoretically feasible, this technology is not commercially available.

CCS requires three distinct processes:

1. Isolation of CO_2 from the waste gas stream;
2. Transportation of the captured CO_2 to a suitable storage location, and;

3. Safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the process in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams including chemical and physical absorption, cryogenic separation, and membrane separation. Only physical and chemical absorption would be considered technically implementable for a high volume, low concentration gas stream. Currently, there are no combined cycle power plants utilizing CO_2 absorption systems. As such, this technology, while theoretically feasible, has not been demonstrated in practice for combined cycle facilities. Even if it were commercially available, the cost for designing, installing and operating this type of capture system would be prohibitive. In addition, the costs of compressing the captured CO_2 to pressures needed for transportation would result in a large parasitic load to the facility, reducing its efficiency and increasing overall emissions of CO_2 and all other regulated pollutants on a per megawatt-hour basis.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Currently CO_2 storage is available at only a very limited number of sites. Geologic conditions at the proposed project site are not suitable for carbon sequestration. NEC does not own or control any other sites that would be appropriate for CO_2 sequestration. The closest commercially available CO_2 sequestration site is in Saskatchewan Canada, over 2,000 miles from the project site. Accordingly, to remain a viable control technology, captured CO_2 would have to be transported to the storage site in order to achieve any environmental benefit. Pipelines are the most common method for transporting large quantities of CO_2 over long distances. There are currently approximately 3,600 miles of existing pipeline located in the United States. However, there is no existing pipeline located near the project site, the nearest pipeline being over 1,000 miles away. As such, a CO_2 transportation pipeline would need to be constructed to tie into the existing pipeline structure. The cost for permitting and constructing this pressurized pipeline would be economically prohibitive.

Based upon the large costs associated with the capture, transportation and storage of CO_2, in addition to the large parasitic load, CCS is considered cost prohibitive and economically infeasible for the project.

Apart from CCS, the only other technology with the potential to reduce GHG from the proposed facility is pollution prevention or the use of inherently lower-emitting processes, practices and designs. Because emissions of CO_2 are directly related to the amount of fuel combusted, an effective means of reducing GHG emissions is through highly efficient combustion technologies. By utilizing more efficient technology, less fuel is required to produce the same amount of output electricity.

The project is designed for baseload electricity generation and will utilize state-of-the-art combustion turbine technology in combined cycle mode. Combined cycle generation takes advantage of the waste heat from the combustion turbines, capturing that heat in the HRSG and generating steam which then powers a conventional steam turbine. Use of waste heat in this manner makes combined cycle projects considerably more efficient than conventional boiler technology.

The project is proposing to use ”F” frame combustion turbines, which utilize highly efficient combustion technology. In addition, the combustion turbines will combust natural gas as their only fuel source. Other fossil fuels generate a greater amount of CO_2 per megawatt-hour of power produced or MMBtu of fuel consumed. As such, using natural gas as the only fuel source effectively minimizes the production of CO_2 from combustion. The proposed project has a “Design Base Heat Rate” of approximately 6,005 Btu/kW-hr (lower heating value [LHV]) at ISO conditions (59 °F, 60 percent relative humidity) with no duct firing.

4.8.1.1 Search of LAER/BACT Determinations

The search of the RBLC identified more than 300 natural gas fired combined cycle projects. However, the RBLC did not provide a CO_2 BACT limit for any of these projects. However, the Bay Area Air Quality Management District (BAAQMD) in California issued a permit in February 2010 for the Russell City Energy Center that included a BACT limit. The Russell City Energy Center is the only final permit for a combined-cycle facility that has included a BACT limit for CO_2. It is a proposed combined-cycle generating facility with a nominal capacity of 600 MW utilizing two Siemens F-class combustion turbines. In the Statement of Basis, the BAAQMD indicated that its BACT determination is based upon a design thermal efficiency of 56.4% (lower heating value [LHV]), which was considered the highest efficiency available for the F-class turbine family at that time. The BAAQMD based this determination on a comparison with other similar facilities in California that had recently been permitted, or were currently undergoing review. They found the 56.4% efficiency to be higher than any other comparable facility. For this reason, the BAAQMD determined that “the 56.4% (LHV) thermal efficiency proposed for the Russell City Energy Center is the best efficiency performance achievable from commercially available systems for a 600 MW combined cycle power plant.”

The Russell City Energy Center PSD Permit established a BACT limit of 7,730 Btu/kW-hr for this facility. This BACT limit is based upon a design base heat rate of 6,852 Btu/kw-hr based on net power output at ISO conditions without duct firing, and includes a reasonable margin of compliance. In its analysis, the BAAQMD evaluated factors that could be reasonably expected to degrade the theoretical design efficiency of the turbines and increase the heat rate. They considered a number of factors including:

- A design margin to reflect that the equipment as constructed and installed may not fully achieve the assumptions that went into the design calculations;
- A reasonable performance degradation margin to reflect normal wear and tear, and;
- A reasonable degradation margin based on normal wear and tear caused by variability in the operation of the auxiliary plant equipment.

Based on their analysis, BAAMD concluded that 12.8 percent was a reasonable compliance margin to add to the design base heat rate to develop a numerical BACT limit.

4.8.1.2 LAER/BACT Determination

The GE 7FA.05 turbines operating in combined cycle mode proposed for the NEC project have a design thermal efficiency of 58.4 percent (LHV) at ISO conditions with no duct firing. In addition, they have a design base heat rate of 6,005 Btu/kW-hr at ISO LHV conditions with no duct firing (based on net output). Both of these values are superior to the efficiencies proposed in the Russell City Energy Center BACT analysis. Based upon these design efficiencies, and adding a reasonable margin of compliance consistent with the BAAQMD analysis for Russell City Energy Center, NEC is proposing a limit of 6,774 Btu/kW-hr LHV (ISO conditions without duct firing) as BACT for the proposed project. This limit represents the lowest heat input rate that can reasonably be assured under all operating scenarios. This level of emissions will be achieved through utilization of high efficiency, state-of-the-art, combustion turbine technology and combusting only commercially available, pipeline quality natural gas in the turbines. This emission level is consistent with the limit provided in the BACT determination for the Russell City Energy Center, and represents the lowest level of CO_2 emissions for combined-cycle power plants demonstrated in practice.

4.9 Emission Limit and Control Technology Summaries

Tables 4-1 and 4-2 summarize the proposed emission limits and associated control technology for the project.

Table 4-1: Summary of Proposed BACT/LAER Emission Limits and Associated Control Technologies for the Combustion Turbines

Pollutant	Emission Rate (lb/MMBtu)	Emission Rate (ppm$_v$) at 15% O_2	Control Technology	Represents
NO_x			DLN and SCR	LAER/BACT/SOTA
CT only	0.0081	2.0		
CT w/ DB	0.0081	2.0		
VOC			Good combustion controls and oxidation catalyst	LAER/SOTA
CT only	0.0015	1.0		
CT w/ DB	0.0029	2.0		
CO			Good combustion controls and oxidation catalyst	BACT/SOTA
CT only	0.0050	2.0		
CT w/ DB	0.0050	2.0		
$PM_{10}/PM_{2.5}$			Low sulfur fuel	BACT/SOTA
CT only	0.0057	n/a		
CT w/ DB	0.0064	n/a		
SO_2			Low sulfur fuel	SOTA
CT only	0.00037	n/a		
CT w/ DB	0.00037	n/a		

Table 4-2: Summary of Proposed BACT/LAER Emission Limits and Associated Control Technologies for the Auxiliary Boiler

Pollutant	Emission Rate (lb/MMBtu)	Control Technology	Represents
NO_x	0.02	LNG and FGR	LAER/BACT /SOTA
VOC	0.005	Good combustion controls	LAER/ /SOTA
CO	0.037	Good combustion controls	BACT/SOTA
$PM_{10}/PM_{2.5}$	0.010	Low sulfur fuel	BACT/SOTA
SO_2	0.0005	Low sulfur fuel	SOTA

5. ENVIRONMENTAL JUSTICE

Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations" (February 1994) requires federal agencies to consider disproportionate adverse human health and environmental impacts on minority and low-income populations. Under this Order, Environmental Justice considerations can be incorporated into PSD review. New Jersey has a similar order in Executive Order 131 requiring state agencies, including NJDEP, to allow for public participation in decisions that affect environmental quality and public health. Executive Order 131 also establishes the Environmental Justice Advisory Council inside NJDEP. The NJDEP requires an EJ review that includes the following components:

- Identification of EJ communities;
- Demonstration that the proposed project will not significantly contribute to a disproportionately high and adverse burden on EJ communities; and
- Development of a plan to allow the public to participate in decisions that affect environmental quality and public health as they relate to the project.

This section provides the first step in this process, identification of EJ communities. The other components in the review are provided in separate documentation.

USEPA Region 2 has issued guidelines for conducting Environmental Justice analyses that involves the following steps:

- Develop geographic boundaries for Community of Concern (COC) and conduct a preliminary burden analysis;
- Compare COC demographics to a statistical reference area;
- Determine if demographic criteria are met;
- Develop a comprehensive environmental load profile;
- Assess whether the burden is disproportionately high and adverse; and
- Summarize and report results.

Currently, NJDEP has no formal guidance for identifying Communities of Concern (COCs). Therefore, NEC has followed the guidance of USEPA Region 2.

For this analysis, NEC used U.S. Census 2000 block groups as boundaries for COCs in the vicinity, typically within three miles, of the project.

NEC used USEPA Region 2's EJ View mapping tool to compare the demographic information of these Census 2000 block groups with USEPA Region 2's demographic criteria for EJ communities (Table 5-1). The cities of Newark and Jersey City meet the criteria for EJ communities and, as shown in Figure 5-1, many of the block groups in the vicinity of the project meet either of the criteria.

Table 5-1: Demographics of Environmental Justice Communities of Concern

Community	Percent Below Poverty	Percent Minority
City of Newark	28.5	85.7
Jersey City	18.9	76.8
Reference Areas		
Essex County	15.6	62.4
Hudson County	15.5	64.7
New Jersey	8.5	34.0
USEPA Region 2 – Statewide Urban Thresholds		
New Jersey	18.58	48.52

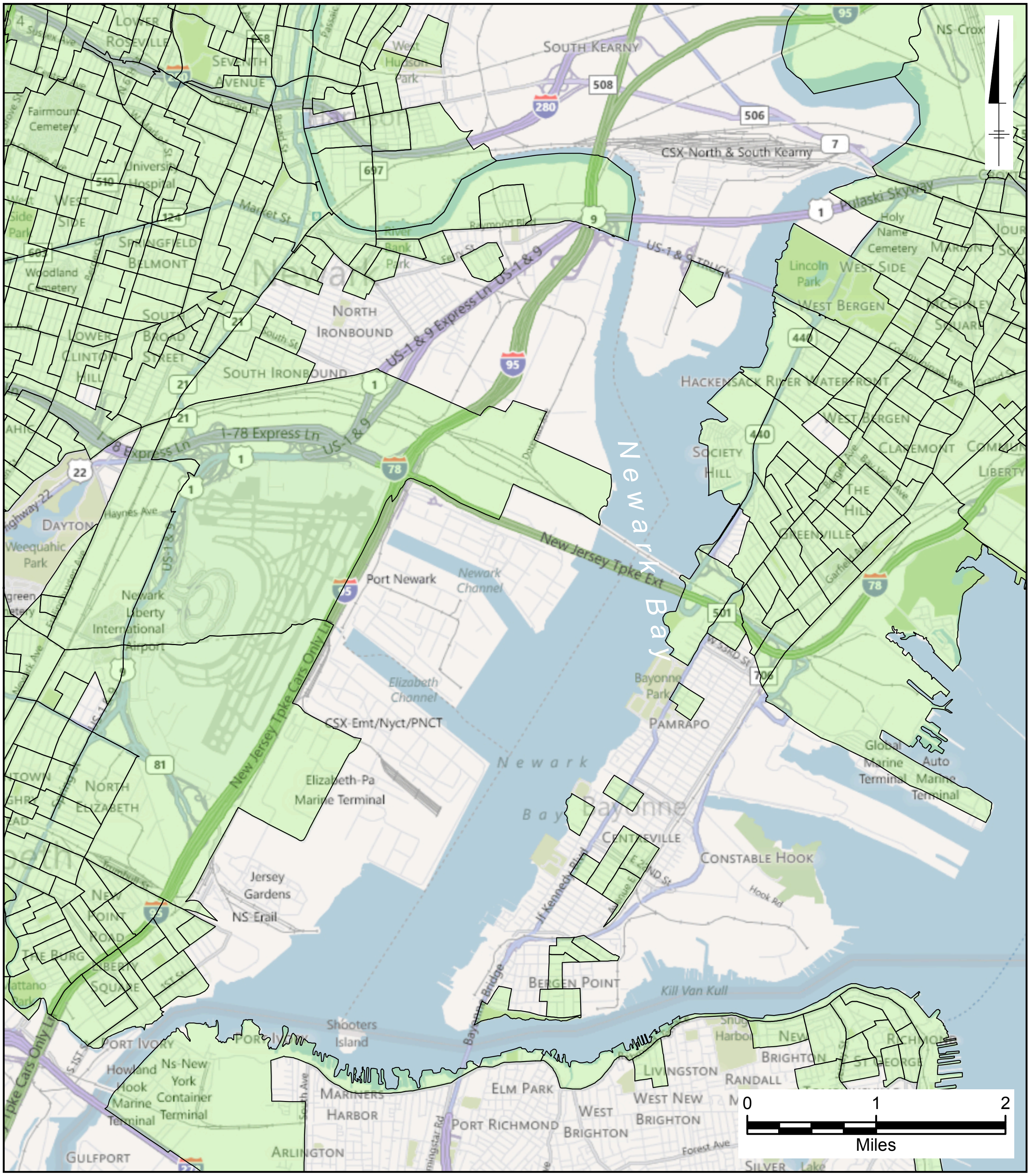
In accordance with Executive Order 12898, a community is a potential EJ community if it is either minority or low income. According to USEPA guidelines, if the COC demographics are equal to or above the identified thresholds (Table 5-1) then the COC is considered a potential environmental justice area that should be more fully evaluated. Figure 5-1 identifies the block groups that meet either of the criteria.

The USEPA guidelines state that while there is no established methodology for evaluating cumulative risk and there are uncertainties associated with assessing environmental burden, when an acknowledged health standard for the burden in question is exceeded, USEPA Region 2 considers the burden to be adverse unless otherwise indicated by supportive data. The COCs and EJ communities are all located within ozone and $PM_{2.5}$

nonattainment areas. These designations alone are enough to consider the environmental burden on the community to be adverse.

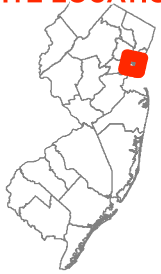
Air dispersion modeling is used to determine which EJ communities have the potential to be significantly impacted by the project. In order to identify those new sources with the potential to significantly affect air quality, USEPA and NJDEP have adopted ambient air quality standards for the protection of human health. They have also established SILs as a screening level. If a project's impacts are found to be below the SILs, then the project will have an insignificant impact on air quality. In addition, a project can demonstrate via cumulative modeling that they are not significantly contributing to a violation of an ambient air quality standard. If the project's air quality impacts are shown to be insignificant, then there will be no disproportionately high and adverse burden on communities in the area. Preliminary modeling suggests that the project will be below SILs for all pollutants and averaging times, with the exception of 1-hour NO_2. Cumulative modeling of NO_2 will demonstrate that the project is not significantly contributing to an exceedance of a NAAQS. The air dispersion modeling indicating that EJ communities are not significantly impacted by the project will be provided in the NEC Dispersion Modeling Report, to be submitted under separate cover.

When a new project is proposed in an area that meets the USEPA Region 2's criteria for environmental justice communities and where those communities have an adverse environmental burden, applicants should work with agencies to reach out to affected communities to address agency and community concerns. With that goal in mind, NEC has prepared a Public Participation Plan in coordination with NJDEP to ensure that the public has the opportunity to comment and participate in permit decisions for the project. This plan will be provided under separate cover.



Legend

🟩 Minority Population >48.52% and/or Poverty >18.58%



SITE LOCATION

NEWARK ENERGY CENTER, LLC
NEWARK, ESSEX COUNTY, NEW JERSEY

QUALIFYING ENVIRONMENTAL JUSTICE CENSUS BLOCK GROUPS

ARCADIS

FIGURE
5-1

CITY: DIV/GROUP: DB: LD: PIC: PM: TM: TR:
Project (Project #)

6. REFERENCES

CARB, 1996. California Air Toxics Emission Factor Database (CATEF) 1996.

Executive Order 12898, “Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations” President William J. Clinton. February 11, 1994.

Federal Register 72:183. “Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers (PM2.5)—Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)” Proposed Rule. p. 54112. September 21, 2007.

USEPA, 1990. *New Source Review Workshop Manual (Draft)*. October 1990.

USEPA, 1993. Alternative Control Techniques Document – NOx Emissions from Stationary Reciprocating Internal Combustion Engines. Office of Air and Radiation. EPA-453/R-93-032. July 1993.

USEPA, 2000a. *Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources*.

USEPA. 2000b. Interim Environmental Justice Policy, “Guidelines for Conduction Environmental Justice Analyses.” USEPA Region 2. December 2000.

USEPS, 2010 “*PSD and Title V Permitting Guidance for Greenhouse Gases*”, Office of Air Quality Planning and Standards, November 2010

VCAPCD, 2001. AB2588 Combustion Emission Factors 2001.

Appendix A

RADIUS Printout

New Jersey Department of Environmental Protection
Facility Profile (General)

Facility Name (AIMS): Hess Newark Energy Center

Facility ID (AIMS): 08857

Street Address: DOREMUS AVE & DELANCY ST
NEWARK, NJ 07105

Mailing Address: MR MICHAEL GREGG
ONE HESS PLZ
WOODBRIDGE, NJ 07095

County: Essex

Location Description:

State Plane Coordinates:

X-Coordinate:

Y-Coordinate:

Units:

Datum:

Source Org.:

Source Type:

Industry:

Primary SIC:

Secondary SIC:

NAICS: 221112

New Jersey Department of Environmental Protection
Facility Profile (General)

Contact Type: Air Permit Information Contact

Organization: ARCADIS US, Inc.
Org. Type: Corporation
Name: Frederick Sellars
NJ EIN:
Title: Vice President
Phone: (978) 937-9999 x0317
Fax: (978) 937-7555 x
Other: ( ) - x
Type:
Email: frederick.sellars@arcadis-us.com

Mailing Address:
Two Executive Drive
Suite 303
Chelmsford, MA 01824

Contact Type: BOP - Operating Permits

Organization: ARCADIS US, Inc.
Org. Type: Corporation
Name: Frederick Sellars
NJ EIN:
Title: Vice President
Phone: (978) 937-9999 x0317
Fax: (978) 937-7555 x
Other: ( ) - x
Type:
Email: frederick.sellars@arcadis-us.com

Mailing Address:
Two Executive Drive
Suite 303
Chelmsford, MA 01824

Contact Type: Consultant

Organization: ARCADIS US, Inc.
Org. Type: Corporation
Name: Frederick Sellars
NJ EIN:
Title: Vice President
Phone: (978) 937-9999 x0317
Fax: (978) 937-7555 x
Other: ( ) - x
Type:
Email: frederick.sellars@arcadis-us.com

Mailing Address:
Two Executive Drive
Suite 303
Chelmsford, MA 01824

New Jersey Department of Environmental Protection
Facility Profile (General)

Contact Type: Fees/Billing Contact

Organization: Hess Corporation

Org. Type: Corporation

Name: Peter

NJ EIN: 00452391369

Title: Director Regulatory & Environmental Comp

Phone: (774) 750-7088 x

Fax: (732) 750-6670 x

Other: ( ) - x

Type:

Email: phaid@hess.com

Mailing Address:
One Hess Plaza
Woodbridge, NJ 07095

Contact Type: General Contact

Organization: Hess Corporation

Org. Type: Corporation

Name: Peter

NJ EIN: 00452391369

Title: Director Regulatory & Environmental Comp

Phone: (774) 750-7088 x

Fax: (732) 750-6670 x

Other: ( ) - x

Type:

Email: phaid@hess.com

Mailing Address:
One Hess Plaza
Woodbridge, NJ 07095

Contact Type: Responsible Official

Organization: Hess Corporation

Org. Type: Corporation

Name: Peter

NJ EIN: 00452391369

Title: Director Regulatory & Environmental Comp

Phone: (774) 750-7088 x

Fax: (732) 750-6670 x

Other: ( ) - x

Type:

Email: phaid@hess.com

Mailing Address:
One Hess Plaza
Woodbridge, NJ 07095

New Jersey Department of Environmental Protection
Facility Profile (Permitting)

1. Is this facility classified as a small business by the USEPA?	No
2. Is this facility subject to N.J.A.C. 7:27-22?	Yes
3. Are you voluntarily subjecting this facility to the requirements of Subchapter 22?	No
4. Has a copy of this application been sent to the USEPA?	No
5. If not, has the EPA waived the requirement?	No
6. Are you claiming any portion of this application to be confidential?	No
7. Is the facility an existing major facility?	Yes
8. Have you submitted a netting analysis?	Yes
9. Are emissions of any pollutant above the SOTA threshold?	Yes
10. Have you submitted a SOTA analysis?	No
11. If you answered "Yes" to Question 9 and "No" to Question 10, explain why a SOTA analysis was not required	Meets SOTA requirements
12. Have you provided, or are you planning to provide air contaminant modeling?	Yes

Air Contaminant(s)	
Name	**CAS Number**
Acrolein	00107-02-8
Benzene	00071-43-2
CO	
Formaldehyde	00050-00-0
Lead compounds	
Nitrogen dioxide	10102-44-0
Ozone	
PM-10 (Total)	
PM-2.5 (Total)	
SO2	
Toluene	00108-88-3
TSP	

Hess Newark Energy Center (08857)

Date: 10/5/2011

New Jersey Department of Environmental Protection
Insignificant Source Emissions

IS NJID	Source/Group Description	Equipment Type	Location Description	Estimate of Emissions (tpy)								
				VOC (Total)	NOx	CO	SO	TSP	PM-10	Pb	HAPS (Total)	Other (Total)
IS1	diesel storage tanks	Storage Vessel		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00000000	0.000
IS2	aqueous ammonia storage tanks (2 20,000 gal tanks)	Storage Vessel		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00000000	0.000
Total				0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00000000	0.000

New Jersey Department of Environmental Protection
Equipment Inventory

Equip. NJID	Facility's Designation	Equipment Description	Equipment Type	Certificate Number	Install Date	Grand-Fathered	Last Mod. (Since 1968)	Equip. Set ID
E1	Turbine 1	Combustion Turbine 1	Combustion Turbine			No		
E2	Turbine 2	Combustion Turbine 2	Combustion Turbine			No		
E3	HRSG 1	HRSG w/Duct Burner 1	Duct Burner			No		
E4	HRSG 2	HRSG w/Duct Burner 2	Duct Burner			No		
E5	Aux Boiler	Auxilary Boiler	Boiler			No		
E6	Em Gen	1.5 MW Emergency Generator	Emergency Generator			No		
E7	Fire Pump	270 HP Fire Pump	Emergency Generator			No		
E8	CoolingTower	Cooling Tower	Other Equipment			No		

000000 E1 (Combustion Turbine)
Print Date: 10/5/2011

Make:

Manufacturer: GE

Model: 7FA.05

Maximum rated Gross Heat Input (MMBtu/hr-HHV): 2,320.00

Type of Turbine:

Type of Cycle: Combined-Cycle Description:

Industrial Application: Electrical Generatoı Description:

Power Output: 320.00 Units: Megawatts

Is the combustion turbine using (check all that apply):

A Dry Low NOx Combustor: ☑

Steam Injection: ☐ Steam to Fuel Ratio

Water Injection: ☐ Water to Fuel Ratio:

Other: ☐ Description:

Is the turbine Equipped with a Duct Burner? ● Yes ○ No

Have you attached a diagram showing the location and/or the configuration of this equipment? ● Yes ○ No

Have you attached any manuf.'s data or specifications to aid the Dept. in its review of this application? ● Yes ○ No

Comments:

000000 E2 (Combustion Turbine)
Print Date: 10/5/2011

Make:

Manufacturer: GE

Model: 7FA.05

Maximum rated Gross Heat Input (MMBtu/hr-HHV): 2,320.00

Type of Turbine:

Type of Cycle: Combined-Cycle   Description:

Industrial Application: Electrical Generatoi   Description:

Power Output: 320.00   Units: Megawatts

Is the combustion turbine using (check all that apply):

A Dry Low NOx Combustor: ☑

Steam Injection: ☐   Steam to Fuel Ratio:

Water Injection: ☐   Water to Fuel Ratio:

Other: ☐   Description:

Is the turbine Equipped with a Duct Burner? ● Yes ○ No

Have you attached a diagram showing the location and/or the configuration of this equipment? ● Yes ○ No

Have you attached any manuf.'s data or specifications to aid the Dept. in its review of this application? ● Yes ○ No

Comments:

000000 E3 (Duct Burner)
Print Date: 10/5/2011

Make:

Manufacturer: GE

Model: TBD

Maximum rated Gross Heat Input (MMBtu/hr-HHV): 211.00

Equipment Type Description: Supplementary-fired heat recovery steam generator (HRSG)

Have you attached a diagram showing the location and/or the configuration of this equipment? ● Yes ○ No

Have you attached any manuf.'s data or specifications to aid the Dept. in its review of this application? ● Yes ○ No

Comments:

Include Emission Rates on the Potential to Emit Screen for each contaminant in ppmvd @ 7%O2 in addition to lbs/hr and tons/yr.

000000 E4 (Duct Burner)
Print Date: 10/5/2011

Make:

Manufacturer: GE

Model: TBD

Maximum rated Gross Heat Input (MMBtu/hr-HHV): 211.00

Equipment Type Description: Supplementary-fired heat recovery steam generator (HRSG)

Have you attached a diagram showing the location and/or the configuration of this equipment? ● Yes ○ No

Have you attached any manuf.'s data or specifications to aid the Dept. in its review of this application? ● Yes ○ No

Comments:

Include Emission Rates on the Potential to Emit Screen for each contaminant in ppmvd @ 7%O2 in addition to lbs/hr and tons/yr.

000000 E5 (Boiler)
Print Date: 10/5/2011

Make:

Manufacturer: TBD

Model: TBD

Maximum Rated Gross Heat Input (MMBtu/hr - HHV): 66.20

Boiler Type:

Utility Type: Utility

Output Type: Steam Only

Steam Output (lb/hr):

Fuel Firing Method:

Description (if other):

Draft Type:

Heat Exchange Type:

Is the boiler using? (check all that apply):

Low NOx Burner: ☑ Type: TODD-RMB

Staged Air Combustion: ☐

Flue Gas Recirculation (FGR): ☑ Amount (%): 35.00

Have you attached a diagram showing the location and/or the configuration of this equipment? Yes

Have you attached any manuf.'s data or specifications to aid the Dept. in its review of this application?

Comments:

000000 E6 (Emergency Generator)
Print Date: 10/5/2011

Make:

Manufacturer: Caterpillar (or equivalent)

Model: TBD

Maximum rated Gross Heat Input (MMBtu/hr-HHV): 14.36

Will the equipment be used in excess of 500 hours per year? ○ Yes ● No

Have you attached a diagram showing the location and/or the configuration of this equipment? ● Yes ○ No

Have you attached any manuf.'s data or specifications to aid the Dept. in its review of this application? ○ Yes ● No

Comments:

000000 E7 (Emergency Generator)
Print Date: 10/5/2011

Make:

Manufacturer: TBD

Model: TBD

Maximum rated Gross Heat Input (MMBtu/hr-HHV): 2.06

Will the equipment be used in excess of 500 hours per year? ○ Yes ● No

Have you attached a diagram showing the location and/or the configuration of this equipment? ● Yes ○ No

Have you attached any manuf.'s data or specifications to aid the Dept. in its review of this application? ○ Yes ● No

Comments:

000000 E8 (Other Equipment)
Print Date: 10/5/2011

Make:

Manufacturer:

Model:

Equipment Type: Cooling Tower

Capacity: 5.40

Units: other units

Description: mega-gallons per day

Have you attached a diagram showing the location and/or the configuration of this equipment? ● Yes ○ No

Have you attached any manuf.'s data or specifications to aid the Dept. in its review of this application? ○ Yes ● No

Comments:

New Jersey Department of Environmental Protection
Control Device Inventory

CD NJID	Facility's Designation	Description	CD Type	Install Date	Grand-Fathered	Last Mod. (Since 1968)	CD Set ID
CD101	SCR 1	Selective Catalytic Reduction for Turbine 1	Selective Catalytic Reduction		No		
CD102	Ox Cat 1	CO Oxidztion Catalyst for Turbine 1	Oxidizer (Catalytic)		No		
CD201	SCR 2	Selective Catalytic Reduction for Turbine 2	Selective Catalytic Reduction		No		
CD202	Ox Cat 2	CO Oxidation Catalyst for Turbine 2	Oxidizer (Catalytic)		No		

000000 CD101 (Selective Catalytic Reduction)
Print Date: 10/5/2011

Make:

Manufacturer: TBD

Model: TBD

Minimum Temperature at Catalyst Bed (°F):

Maximum Temperature at Catalyst Bed (°F):

Minimum Temperature at Reagent Injection Point (°F):

Maximum Temperature at Reagent Injection Point (°F):

Type of Reagent: Ammonia ▼

Description:

Chemical Formula of Reagent:

Minimum Reagent Charge Rate (gpm):

Maximum Reagent Charge Rate (gpm):

Minimum Concentration of Reagent in Solution (% Volume):

Minimum NOx to Reagent Mole Ratio:

Maximum NOx to Reagent Mole Ratio:

Maximum Anticipated Ammonia Slip (ppm):

Type of Catalyst:

Volume of Catalyst (ft³):

Form of Catalyst:

Anticipated Life of Catalyst:

Units: ▼

Have you attached a catalyst replacement schedule? ○ Yes ● No

Method of Determining Breakthrough:

Maximum Number of Sources Using this Apparatus as a Control Device (Include Permitted and Non-Permitted Sources): 2

Alternative Method to Demonstrate Control Apparatus is Operating Properly:

Have you attached any manufacturer's data or specifications in support of the feasibility and/or effectiveness of this control apparatus? ○ Yes ● No

Have you attached a diagram showing the location and/or configuration of this control apparatus? ○ Yes ● No

000000 CD101 (Selective Catalytic Reduction)
Print Date: 10/5/2011

Comments:	The maximum concentration of ammonia in solution is 19% by weight

000000 CD102 (Oxidizer (Catalytic))
Print Date: 10/5/2011

Make:

Manufacturer: TBD

Model: TBD

Minimum Inlet Temperature (°F):

Maximum Inlet Temperature (°F)

Minimum Outlet Temperature (°F)

Maximum Outlet Temperature (°F):

Minimum Residence Time (sec)

Fuel Type:

Description:

Maximum Rated Gross Heat Input (MMBtu/hr):

Minimum Pressure Drop Across Catalyst (psi):

Maximum Pressure Drop Across Catalyst (psi):

Catalyst Material:

Form of Catalyst:

Description:

Minimum Expected Life of Catalyst:

Units:

Volume of Catalyst (ft^3):

Maximum Number of Sources Using this Apparatus as a Control Device (Include Permitted and Non-Permitted Sources): 2

Alternative Method to Demonstrate Control Apparatus is Operating Properly:

Have you attached data from recent performance testing? ○ Yes ● No

Have you attached any manufacturer's data or specifications in support of the feasibility and/or effectiveness of this control apparatus? ○ Yes ● No

Have you attached a diagram showing the location and/or configuration of this control apparatus? ○ Yes ● No

Comments:

000000 CD201 (Selective Catalytic Reduction)
Print Date: 10/5/2011

Make:

Manufacturer: TBD

Model: TBD

Minimum Temperature at Catalyst Bed (°F):

Maximum Temperature at Catalyst Bed (°F):

Minimum Temperature at Reagent Injection Point (°F):

Maximum Temperature at Reagent Injection Point (°F):

Type of Reagent: Ammonia

Description:

Chemical Formula of Reagent:

Minimum Reagent Charge Rate (gpm):

Maximum Reagent Charge Rate (gpm):

Minimum Concentration of Reagent in Solution (% Volume):

Minimum NOx to Reagent Mole Ratio:

Maximum NOx to Reagent Mole Ratio:

Maximum Anticipated Ammonia Slip (ppm):

Type of Catalyst:

Volume of Catalyst (ft^3):

Form of Catalyst:

Anticipated Life of Catalyst:

Units:

Have you attached a catalyst replacement schedule? ○ Yes ● No

Method of Determining Breakthrough:

Maximum Number of Sources Using this Apparatus as a Control Device (Include Permitted and Non-Permitted Sources): 2

Alternative Method to Demonstrate Control Apparatus is Operating Properly:

Have you attached any manufacturer's data or specifications in support of the feasibility and/or effectiveness of this control apparatus? ○ Yes ● No

Have you attached a diagram showing the location and/or configuration of this control apparatus? ○ Yes ● No

000000 CD201 (Selective Catalytic Reduction)
Print Date: 10/5/2011

Comments: The maximum concentration of ammonia in solution is 19% by weight

000000 CD202 (Oxidizer (Catalytic))
Print Date: 10/5/2011

Make:

Manufacturer: TBD

Model: TBD

Minimum Inlet Temperature (°F):

Maximum Inlet Temperature (°F)

Minimum Outlet Temperature (°F)

Maximum Outlet Temperature (°F):

Minimum Residence Time (sec)

Fuel Type:

Description:

Maximum Rated Gross Heat Input (MMBtu/hr):

Minimum Pressure Drop Across Catalyst (psi):

Maximum Pressure Drop Across Catalyst (psi):

Catalyst Material:

Form of Catalyst:

Description:

Minimum Expected Life of Catalyst:

Units:

Volume of Catalyst (ft³):

Maximum Number of Sources Using this Apparatus as a Control Device (Include Permitted and Non-Permitted Sources): 2

Alternative Method to Demonstrate Control Apparatus is Operating Properly:

Have you attached data from recent performance testing? ○ Yes ● No

Have you attached any manufacturer's data or specifications in support of the feasibility and/or effectiveness of this control apparatus? ○ Yes ● No

Have you attached a diagram showing the location and/or configuration of this control apparatus? ○ Yes ● No

Comments:

Hess Newark Energy Center (08857)

Date: 10/5/2011

New Jersey Department of Environmental Protection
Emission Points Inventory

PT NJID	Facility's Designation	Description	Config.	Equiv. Diam. (in.)	Height (ft.)	Dist. to Prop. Line (ft)	Exhaust Temp. (deg. F)			Exhaust Vol. (acfm)			Discharge Direction	PT Set ID
							Avg.	Min.	Max.	Avg.	Min.	Max.		
PT1	Turbine 1	Turbine 1, HRSG, & Aux. Blr Emission Point	Round	264	255	185	181.2	161.3	300.0	1,121,050.0	0.0	1,232,750.0	Up	
PT2	Turbine 2	Turbine 2 & HRSG Emission Point	Round	264	255	185	181.2	161.3	187.3	1,121,050.0	0.0	1,232,750.0	Up	
PT6	Em Gen	Emergency Generator Emission Point	Round	12	50	422	775.9	775.9	775.9	11,174.0	0.0	11,174.0	Up	
PT7	Fire Pump	Fire Pump Emission Point	Round	12	50	283	750.0	750.0	750.0	1,644.0	0.0	1,644.0	Up	
PT8	CoolingTower	Cooling Tower Emission Point (diameter is per cell)	Round	360	65	23	85.0	32.0	120.0	3,944.0	0.0	3,944.0	Up	

New Jersey Department of Environmental Protection
Emission Unit/Batch Process Inventory

U 1 Turbines 2 Turbines, 2 HRSGs, and Aux. Boiler

UOS NJID	Facility's Designation	UOS Description	Operation Type	Signif. Equip.	Control Device(s)	Emission Point(s)	SCC(s)	Annual Oper. Hours		VOC Range	Flow (acfm)		Temp. (deg F)	
								Min.	Max.		Min.	Max.	Min.	Max.
OS1	Turbine 1	Combustion Turbine 1 firing natural gas	Normal - Steady State	E1	CD101 (P) CD102 (S)	PT1		0.0	8,760.0		0.0	1,232,750.0	161.3	187.3
OS2	Turbine 2	Combustion Turbine 2 firing natural gas	Normal - Steady State	E2	CD201 (P) CD202 (P)	PT2		0.0	8,760.0		0.0	1,232,750.0	161.3	187.3
OS3	HRSG 1	Heat Recovery Steam Generator (HRSG) for Turbine 1	Normal - Steady State	E3	CD101 (P) CD102 (S)	PT1		0.0	1,800.0		0.0	1,232,750.0	161.3	187.3
OS4	HRSG 2	Heat Recovery Steam Generator (HRSG) for Turbine 2	Normal - Steady State	E4	CD201 (P) CD202 (S)	PT2		0.0	1,800.0		0.0	1,232,750.0	161.3	187.3
OS5	Aux. Boiler	Auxilary Boiler	Normal - Steady State	E5		PT1		0.0	800.0		0.0	19,301.0	300.0	300.0
OS6	Turbine 1-SU	Combustion Turbine 1 start-up	Startup	E1	CD101 (P) CD102 (S)	PT1		0.0	467.0		0.0	1,232,750.0	161.3	187.3
OS7	Turbine 2-SU	Combustion Turbine 2 start-up	Startup	E2	CD201 (P) CD202 (S)	PT2		0.0	467.0		0.0	1,232,750.0	161.3	187.3
OS8	Turbine 1-SD	Combustion Turbine 1 shutdown	Shutdown	E1	CD101 (P) CD102 (S)	PT1		0.0	90.0		0.0	1,232,750.0	161.3	187.3
OS9	Turbine 2-SD	Combustion Turbine 2 shutdown	Shutdown	E2	CD201 (P) CD202 (S)	PT2		0.0	90.0		0.0	1,232,750.0	161.3	187.3

New Jersey Department of Environmental Protection
Emission Unit/Batch Process Inventory

U 2 CoolingTower Cooling Tower

UOS NJID	Facility's Designation	UOS Description	Operation Type	Signif. Equip.	Control Device(s)	Emission Point(s)	SCC(s)	Annual Oper. Hours		VOC Range	Flow (acfm)		Temp. (deg F)	
								Min.	Max.		Min.	Max.	Min.	Max.
OS1	CoolingTower	Cooling Tower	Normal - Steady State	E8		PT8		0.0	8,760.0		0.0	3,944.0	32.0	120.0

U 3 Em Gen 1.5 MW Emergency Generator

UOS NJID	Facility's Designation	UOS Description	Operation Type	Signif. Equip.	Control Device(s)	Emission Point(s)	SCC(s)	Annual Oper. Hours		VOC Range	Flow (acfm)		Temp. (deg F)	
								Min.	Max.		Min.	Max.	Min.	Max.
OS1	Em Gen	1.5 MW Emergency Generator	Normal - Steady State	E6		PT6		0.0	100.0		0.0	11,174.0	70.0	775.9

New Jersey Department of Environmental Protection
Emission Unit/Batch Process Inventory

U 4 Fire Pump 270 HP Fire Pump

UOS NJID	Facility's Designation	UOS Description	Operation Type	Signif. Equip.	Control Device(s)	Emission Point(s)	SCC(s)	Annual Oper. Hours		VOC	Flow (acfm)		Temp. (deg F)	
								Min.	Max.	Range	Min.	Max.	Min.	Max.
OS1	Fire Pump	270 HP Fire Pump	Normal - Steady State	E7		PT7		0.0	100.0		0.0	1,644.0	70.0	750.0

000000 U1 OS1 (Fuel Information Table)

Print Date: 10/5/2011

Is this fuel a blend?	○ Yes ● No
Fuel Category:	Commercial
Fuel Type:	Natural gas
Description (if other):	
Amount of Sulfur in Fuel (%):	
Amount of Ash in Fuel (%):	
Fuel Heating Value:	1,020.00
Units:	BTU/scf
Estimated Maximum Amount of Fuel Burned Annually:	
Units:	
Estimated Actual Amount of Fuel Burned Annually:	
Units:	
Amount of Oxygen in Flue Gas (%):	
Amount of Moisture in Flue Gas (%):	
Comments:	

000000 U1 OS1 (Efficiency Table - CD101)
Print Date: 10/5/2011

Pollutant Category	Capture Efficiency (%)	Removal Efficiency (%)	Overall Efficiency (%)
CO			
HAP (Total)			
NOx			
Other (Total)			
Pb			
PM-10			
PM-2.5			
SO2			
TSP			
VOC (Total)			

000000 U1 OS2 (Fuel Information Table)

Print Date: 10/5/2011

Is this fuel a blend? ○ Yes ● No

Fuel Category: Commercial

Fuel Type: Natural gas

Description (if other):

Amount of Sulfur in Fuel (%):

Amount of Ash in Fuel (%):

Fuel Heating Value: 1,020.00

Units: BTU/scf

Estimated Maximum Amount of Fuel Burned Annually:

Units:

Estimated Actual Amount of Fuel Burned Annually:

Units:

Amount of Oxygen in Flue Gas (%):

Amount of Moisture in Flue Gas (%):

Comments:

000000 U1 OS3 (Fuel Information Table)

Print Date: 10/5/2011

Is this fuel a blend? ○ Yes ● No

Fuel Category: Commercial

Fuel Type: Natural gas

Description (if other):

Amount of Sulfur in Fuel (%):

Amount of Ash in Fuel (%):

Fuel Heating Value: 1,020.00

Units: BTU/scf

Estimated Maximum Amount of Fuel Burned Annually:

Units:

Estimated Actual Amount of Fuel Burned Annually:

Units:

Amount of Oxygen in Flue Gas (%):

Amount of Moisture in Flue Gas (%):

Comments:

000000 U1 OS4 (Fuel Information Table)
Print Date: 10/5/2011

Is this fuel a blend?	○ Yes ● No
Fuel Category:	Commercial
Fuel Type:	Natural gas
Description (if other):	
Amount of Sulfur in Fuel (%):	
Amount of Ash in Fuel (%):	
Fuel Heating Value:	1,020.00
Units:	BTU/scf
Estimated Maximum Amount of Fuel Burned Annually:	
Units:	
Estimated Actual Amount of Fuel Burned Annually:	
Units:	
Amount of Oxygen in Flue Gas (%):	
Amount of Moisture in Flue Gas (%):	
Comments:	

000000 U1 OS5 (Primary Fuel)

Print Date: 10/5/2011

Is this fuel a blend? No

Fuel Category: Commercial

Fuel Type: Natural gas

Description (if other):

Amount of Sulfur in Fuel (%):

Amount of Ash in Fuel (%):

Fuel Heating Value: 1,020.00

Units: BTU/scf

Estimated Maximum Amount of Fuel Burned Annually:

Units:

Estimated Actual Amount of Fuel Burned Annually:

Units:

Amount of Oxygen in Flue Gas (%):

Amount of Moisture in Flue Gas (%):

Comments:

000000 U3 OS1 (Fuel Information Table)
Print Date: 10/5/2011

Fuel Type:	Diesel fuel
Description (if other):	
Amount of Sulfur in Fuel (%):	
Amount of Ash in Fuel (%):	
Fuel Heating Value:	137,000.00
Units:	BTU/gal
Estimated Maximum Amount of Fuel Burned Annually:	
Units:	
Estimated Actual Amount of Fuel Burned Annually:	
Units:	
Comments:	ULSD - Sulfur content 0.0015

000000 U4 OS1 (Fuel Information Table)
Print Date: 10/5/2011

Fuel Type:	Diesel fuel
Description (if other):	
Amount of Sulfur in Fuel (%):	
Amount of Ash in Fuel (%):	
Fuel Heating Value:	137,000.00
Units:	BTU/gal
Estimated Maximum Amount of Fuel Burned Annually:	
Units:	
Estimated Actual Amount of Fuel Burned Annually:	
Units:	
Comments:	ULSD - Sulfur content 0.0015

New Jersey Department of Environmental Protection
Subject Item Group Inventory

Group NJID: GR1 Unit 1

Members:

Type	ID	OS	Step
U	U 1	OS1 Turbine 1	
U	U 1	OS2 Turbine 2	
U	U 1	OS3 HRSG 1	
U	U 1	OS4 HRSG 2	

Formal Reason(s) for Group/Cap:

☑ Other

Other (explain): Turbines with Duct Burning

Condition/Requirements that will be complied with or are no longer applicable as a result of this Group:

The duct burners will not operate independent of the turbines. Turbine with duct burning is limited to 1800 hours per year per unit. Hourly emission rates provided in the PTE section are for one turbine with on HRSG

Operating Circumstances:

The duct burners will not operate independent of the turbines. Turbine with duct burning is limited to 1800 hours per year per unit.

New Jersey Department of Environmental Protection
Potential to Emit

Subject Item: **FC**

Operating Scenario:

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
Acrolein			0.02900000	0.02900000	tons/yr	No
Benzene			0.24000000	0.24000000	tons/yr	No
CO			486.30000000	486.30000000	tons/yr	No
Formaldehyde			2.22000000	2.22000000	tons/yr	No
NOx (Total)			143.60000000	143.60000000	tons/yr	No
PM-10 (Total)			96.10000000	96.10000000	tons/yr	No
PM-2.5 (Total)			93.10000000	93.10000000	tons/yr	No
SO2			6.20000000	6.20000000	tons/yr	No
Toluene			2.59000000	2.59000000	tons/yr	No
TSP			96.10000000	96.10000000	tons/yr	No
VOC (Total)			35.80000000	35.80000000	tons/yr	No

Subject Item: **GR1 Unit 1**

Operating Scenario:

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
CO			10.00000000	10.00000000	lb/hr	No
NOx (Total)			16.40000000	16.40000000	lb/hr	No
PM-10 (Total)			11.90000000	11.90000000	lb/hr	No
PM-2.5 (Total)			11.90000000	11.90000000	lb/hr	No
SO2			0.76000000	0.76000000	lb/hr	No
TSP			11.90000000	11.90000000	lb/hr	No
VOC (Total)			5.70000000	5.70000000	lb/hr	No

New Jersey Department of Environmental Protection
Potential to Emit

Subject Item: **U1 Turbines**

Operating Scenario: **OS0 Summary**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
Acrolein			0.02900000	0.02900000	tons/yr	No
Benzene			0.24000000	0.24000000	tons/yr	No
CO			485.68000000	485.68000000	tons/yr	No
Formaldehyde			2.21000000	2.21000000	tons/yr	No
NOx (Total)			142.63000000	142.63000000	tons/yr	No
PM-10 (Total)			90.56000000	90.56000000	tons/yr	No
PM-2.5 (Total)			90.56000000	90.56000000	tons/yr	No
SO2			6.21000000	6.21000000	tons/yr	No
Toluene			2.59000000	2.59000000	tons/yr	No
TSP			90.56000000	90.56000000	tons/yr	No
VOC (Total)			35.63000000	35.63000000	tons/yr	No

Subject Item: **U1 Turbines**

Operating Scenario: **OS1**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
Acrolein			0.00620000	0.00620000	lb/hr	No
Benzene			0.03000000	0.03000000	lb/hr	No
CO			9.20000000	9.20000000	lb/hr	No
Formaldehyde			0.26000000	0.26000000	lb/hr	No
NOx (Total)			15.10000000	15.10000000	lb/hr	No
PM-10 (Total)			9.90000000	9.90000000	lb/hr	No
PM-2.5 (Total)			9.90000000	9.90000000	lb/hr	No

New Jersey Department of Environmental Protection
Potential to Emit

Subject Item: **U1 Turbines**

Operating Scenario: **OS1**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
SO2			0.69000000	0.69000000	lb/hr	No
Toluene			0.30000000	0.30000000	lb/hr	No
TSP			9.90000000	9.90000000	lb/hr	No
VOC (Total)			2.60000000	2.60000000	lb/hr	No

Subject Item: **U1 Turbines**

Operating Scenario: **OS2**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
Acrolein			0.00620000	0.00620000	lb/hr	No
Benzene			0.03000000	0.03000000	lb/hr	No
CO			9.20000000	9.20000000	lb/hr	No
Formaldehyde			0.26000000	0.26000000	lb/hr	No
NOx (Total)			15.10000000	15.10000000	lb/hr	No
PM-10 (Total)			9.90000000	9.90000000	lb/hr	No
PM-2.5 (Total)			9.90000000	9.90000000	lb/hr	No
SO2			0.69000000	0.69000000	lb/hr	No
Toluene			0.30000000	0.30000000	lb/hr	No
TSP			9.90000000	9.90000000	lb/hr	No
VOC (Total)			2.60000000	2.60000000	lb/hr	No

New Jersey Department of Environmental Protection
Potential to Emit

Subject Item: **U1 Turbines**

Operating Scenario: **OS3**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
CO			0.80000000	0.80000000	lb/hr	No
NOx (Total)			1.30000000	1.30000000	lb/hr	No
PM-10 (Total)			2.00000000	2.00000000	lb/hr	No
PM-2.5 (Total)			2.00000000	2.00000000	lb/hr	No
SO2			0.07000000	0.07000000	lb/hr	No
TSP			2.00000000	2.00000000	lb/hr	No
VOC (Total)			3.10000000	3.10000000	lb/hr	No

Subject Item: **U1 Turbines**

Operating Scenario: **OS4**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
CO			0.80000000	0.80000000	lb/hr	No
NOx (Total)			1.30000000	1.30000000	lb/hr	No
PM-10 (Total)			2.00000000	2.00000000	lb/hr	No
PM-2.5 (Total)			2.00000000	2.00000000	lb/hr	No
SO2			0.07000000	0.07000000	lb/hr	No
TSP			2.00000000	2.00000000	lb/hr	No
VOC (Total)			3.10000000	3.10000000	lb/hr	No

New Jersey Department of Environmental Protection
Potential to Emit

Subject Item: **U1 Turbines**

Operating Scenario: **OS5**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
CO			2.45000000	2.45000000	lb/hr	No
NOx (Total)			1.32000000	1.32000000	lb/hr	No
PM-10 (Total)			0.66000000	0.66000000	lb/hr	No
PM-2.5 (Total)			0.66000000	0.66000000	lb/hr	No
SO2			D	D	lb/hr	No
TSP			0.66000000	0.66000000	lb/hr	No
VOC (Total)			0.33000000	0.33000000	lb/hr	No

Subject Item: **U2 CoolingTower**

Operating Scenario: **OS0 Summary**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
PM-10 (Total)			5.52300000	5.52300000	tons/yr	No
PM-2.5 (Total)			2.51100000	2.51100000	tons/yr	No
TSP			10.03000000	10.03000000	tons/yr	No

Subject Item: **U2 CoolingTower**

Operating Scenario: **OS1**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
PM-10 (Total)			1.26100000	1.26100000	lb/hr	No
PM-2.5 (Total)			0.57300000	0.57300000	lb/hr	No

New Jersey Department of Environmental Protection
Potential to Emit

Subject Item: **U2 CoolingTower**

Operating Scenario: **OS1**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
TSP			1.26100000	1.26100000	lb/hr	No

Subject Item: **U3 Em Gen**

Operating Scenario: **OS0 Summary**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
Benzene			0.00067000	0.00067000	tons/yr	No
CO			0.58000000	0.58000000	tons/yr	No
NOx (Total)			0.93000000	0.93000000	tons/yr	No
PM-10 (Total)			0.03000000	0.03000000	tons/yr	No
PM-2.5 (Total)			0.03000000	0.03000000	tons/yr	No
SO2			0.03000000	0.03000000	tons/yr	No
TSP			D	D	tons/yr	No
VOC (Total)			0.13000000	0.13000000	tons/yr	No

Subject Item: **U3 Em Gen**

Operating Scenario: **OS1**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
Benzene			0.01300000	0.01300000	lb/hr	No
CO			11.56000000	11.56000000	lb/hr	No
NOx (Total)			18.53000000	18.53000000	lb/hr	No

New Jersey Department of Environmental Protection
Potential to Emit

Subject Item: **U3 Em Gen**

Operating Scenario: **OS1**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
PM-10 (Total)			0.66000000	0.66000000	lb/hr	No
PM-2.5 (Total)			0.66000000	0.66000000	lb/hr	No
SO2			D	D	lb/hr	No
TSP			0.66000000	0.66000000	lb/hr	No
VOC (Total)			2.62000000	2.62000000	lb/hr	No

Subject Item: **U4 Fire Pump**

Operating Scenario: **OS0 Summary**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
CO			0.08000000	0.08000000	tons/yr	No
NOx (Total)			0.08000000	0.08000000	tons/yr	No
PM-10 (Total)			0.00400000	0.00400000	tons/yr	No
PM-2.5 (Total)			0.00400000	0.00400000	tons/yr	No
SO2			D	D	tons/yr	No
TSP			0.00400000	0.00400000	tons/yr	No
VOC (Total)			0.01000000	0.01000000	tons/yr	No

New Jersey Department of Environmental Protection
Potential to Emit

Subject Item: **U4 Fire Pump**

Operating Scenario: **OS1**

Step:

Air Contaminant Category (HAPS)	Fugitive Emissions	Emissions Before Controls	Emissions After Controls	Total Emissions	Units	Alt. Em. Limit
CO			1.55000000	1.55000000	lb/hr	No
NOx (Total)			1.55000000	1.55000000	lb/hr	No
PM-10 (Total)			0.09000000	0.09000000	lb/hr	No
PM-2.5 (Total)			0.09000000	0.09000000	lb/hr	No
SO2			D	D	lb/hr	No
TSP			0.09000000	0.09000000	lb/hr	No
VOC (Total)			0.22000000	0.22000000	lb/hr	No

New Jersey Department of Environmental Protection
Facility Specific Requirements

Subject Item: **FC**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	General Provisions: Defines numerous terms used in N.J.A.C. 7:27. Specifies procedures for making confidentiality claims, certifying applications, reports, and other documents to the Department, and requesting adjudicatory hearings and stays of the effective date of departmental decisions. Also, provides provisions regarding applicability, severability, and liberal construction of N.J.A.C. 7:27. [N.J.A.C. 7:27- 1]	None.	None.	None.
2	Control and Prohibition of Open Burning: Prohibits any person from open burning of rubbish, garbage, trade waste, buildings, structures, leaves, other plant life and salvage. Open burning of infested plant life or dangerous material may only be performed with a permit from the Department. [N.J.A.C. 7:27- 2]	None.	None.	Obtain an approved permit: Prior to occurrence of event (prior to open burning). [N.J.A.C. 7:27- 2]
3	Prohibition of Air Pollution: Notwithstanding compliance with other subchapters of N.J.A.C. 7:27, no person shall suffer, allow, or permit to be emitted into the outdoor atmosphere substances in quantities that result in air pollution as defined at N.J.A.C. 7:27-5.1. Applicable to all facilities located in New Jersey. [N.J.A.C. 7:27- 5]	None.	None.	None.
4	Prevention and Control of Air Pollution Control Emergencies: Requires that written Standby Plans, consistent with good industrial practice and safe operating procedures, be prepared for reducing the emission of air contaminants during periods of an air pollution alert, warning, or emergency. Any person responsible for the operation of a source of air contamination not set forth in Table 1 of N.J.A.C. 7:27-12 is not required to prepare such a plan unless requested by the Department in writing. [N.J.A.C. 7:27-12]	None.	None.	Comply with the requirement: Upon occurrence of event. Upon proclamation by the Governor of an air pollution alert, warning, or emergency, the permittee shall put the Standby Plan into effect. In addition, the permittee shall ensure that all of the applicable emission reduction objectives of N.J.A.C. 7:27-12.4, Table I, II, and III are complied with whenever there is an air pollution alert, warning, or emergency. [N.J.A.C. 7:27-12]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
5	Emission Offsets Rules. [N.J.A.C. 7:27-18]	Other: When applying for minor/significant modification, demonstrate compliance with this applicable requirement which may call for specific monitoring and/or recordkeeping activities. [N.J.A.C. 7:27-18].	Other: When applying for minor/significant modification, demonstrate compliance with this applicable requirement which may call for specific monitoring and/or recordkeeping activities. [N.J.A.C. 7:27-18].	Comply with the requirement: Upon occurrence of event. Submit an administratively complete application when applying for a minor modification pursuant to N.J.A.C. 7:27-22.23 or a significant modification pursuant to N.J.A.C. 7:27-22.24. [N.J.A.C. 7:27-22]
6	Emissions Statements: Submit an annual emission statement (if required) electronically to the NJDEP by May 15 of each year (or by mutually agreed upon date, but no later than June 15 of each year). [N.J.A.C. 7:27-21]	Other: The emission statement will be based on monitoring, recording and recordkeeping of actual emissions, capture and control efficiencies, process rate and operating data for source operations with the potential to emit certain air contaminants. [N.J.A.C. 7:27-21].	Other: The emission statement and all supporting records shall be maintained on the operating premises for a period of five (5) years from the due date of each emission statement. [N.J.A.C. 7:27-21].	Submit an Annual Emission Statement: Annually (if required) electronically by May 15 or by any mutually agreed upon date, but not later than June 15 of each year. [N.J.A.C. 7:27-21]
7	Compliance Certification: Submit annual compliance certification for each applicable requirement, pursuant to N.J.A.C. 7:27-22.19(f), within 60 days after the end of each calendar year during which this permit was in effect. [N.J.A.C. 7:27-22]	None.	None.	Submit an Annual Compliance Certification: Annually to the Department and EPA on forms provided by the Department within 60 days after the end of each calendar year during which this permit was in effect. The annual compliance certification reporting period will cover the calendar year ending December 31. Forms provided by the Department can be found on the Department's web site at the following link: http://www.nj.gov/dep/enforcement/compliancecertsair.htm [N.J.A.C. 7:27-22]
8	Prevention of Air Pollution from Architectural Coatings and Consumer Products. [N.J.A.C. 7:27-23]	None.	None.	None.
9	Any operation of equipment which causes off-property effects, including odors, or which might reasonably result in citizen's complaints shall be reported to the Department to the extent required by the Air Pollution Control Act, N.J.S.A. 26:2C-19(e). [N.J.S.A. 26:2C-19(e)]	Other: Observation of plant operations. [N.J.S.A. 26:2C-19(e)].	Other: Maintain a copy of all information submitted to the Department. [N.J.S.A. 26:2C-19(e)].	Notify by phone: Upon occurrence of event. A person who causes a release of air contaminants in a quantity or concentration which poses a potential threat to public health, welfare or the environment or which might reasonably result in citizen complaints shall immediately notify the Department. Such notification shall be made by calling the Environmental Action Hotline at (877) 927-6337. [N.J.S.A. 26:2C-19(e)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
10	Prevention of Significant Deterioration (PSD). [40 CFR 52.21]	Other: When applying for minor/significant modification, demonstrate compliance with this applicable requirement which may call for specific monitoring and/or recordkeeping activities. [40 CFR 52.21].	Other: When applying for minor/significant modification, demonstrate compliance with this applicable requirement which may call for specific monitoring and/or recordkeeping activities. [40 CFR 52.21].	Comply with the requirement: Upon occurrence of event. If subject to PSD, the permittee shall submit an administratively complete application when applying for a significant modification pursuant to N.J.A.C. 7:27-22.24. [N.J.A.C. 7:27-22]
11	National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Asbestos. [40 CFR 61]	Other: Comply with 40 CFR 61.145 and 61.150 when conducting any renovation or demolition activities at the facility. [40 CFR 61].	Other: Comply with 40 CFR 61.145 and 61.150 when conducting any renovation or demolition activities at the facility. [40 CFR 61].	Comply with the requirement: Upon occurrence of event. The permittee shall comply with 40 CFR 61.145 and 61.150 when conducting any renovation or demolition activities at the facility. [40 CFR 61]
12	Protection of Stratospheric Ozone:1) If the permittee manufactures, transforms, destroys, imports, or exports a Class I or Class II substance, the permittee is subject to all the requirements as specified at 40 CFR 82, Subpart A; 2) If the permittee performs a service on motor "fleet" vehicles when this service involves an ozone depleting substance refrigerant (or regulated substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified at 40 CFR 82, Subpart B. 3) The permittee shall comply with the standards for labeling of products containing or manufactured with ozone depleting substances pursuant to 40 CFR 82, Subpart E. 4). The permittee shall comply with the standards for recycling and emission reductions of Class I and Class II refrigerants or a regulated substitute substance during the service, maintenance, repair, and disposal of appliances pursuant to 40 CFR 82, Subpart F, except as provided for motor vehicle air conditioners (MVACs) in Subpart B. 5) The permittee shall be allowed to switch from any ozone depleting substance to any alternative that is listed in the Significant New Alternative Program (SNAP) promulgated pursuant to 40 CFR 82, Subpart G. [40 CFR 82]	Other: Comply with 40 CFR 82 Subparts A, B, E, F, and G. [40 CFR 82].	Other: Comply with 40 CFR 82 Subparts A, B, E, F, and G. [40 CFR 82].	Comply with the requirement: Upon occurrence of event. The permittee shall comply with 40 CFR 82 Subparts A, B, E, F, and G. [40 CFR 82]

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
13	Deviation Report: In accordance with N.J.A.C. 7:27-22.19(c) and 22.19(d)3, the permittee shall submit to the Department, on forms provided by the Department, a certified six-month deviation report relating to testing and monitoring required by the operating permit, not including information for stack emissions testing or continuous emissions monitoring which have other reporting schedules specified in the permit (normally, stack test report is submitted within 45 days of test completion and continuous monitor reporting is done quarterly). Pursuant to N.J.A.C. 7:27-22.19(e), the six-month report must address other specified monitoring, including continuous and periodic monitoring requirements found in column 2 and 3, entitled "Monitoring Requirement" and "Recordkeeping Requirement," respectively, of the Facility Specific Requirements section of this permit. These six-month reports shall clearly identify all deviations from operating permit requirements, the probable cause of such deviations, and any corrective actions or preventive measures taken. If no deviations occurred, the report should say so. Any "None" listed in the Submittal/Action Requirement in the Operating Permit is not intended to override the six-month deviation report. [N.J.A.C. 7.27-22.19(d)3, N.J.A.C. 7.27-22.19(e), and [N.J.A.C. 7:27-22.19(c)]	None.	Other: The permittee shall maintain deviation reports for a period of five years from the date each report is submitted to the Department. [N.J.A.C. 7:27-22.19(a)].	Submit a report: As per the approved schedule. The six-month reports for other specified testing or monitoring required by the operating permit performed from January 1 through June 30 shall be submitted by July 30 of the same calendar year, and from July 1 through December 31, shall be submitted by January 30 of the following calendar year. The report shall be submitted to the Regional Enforcement Office and shall be certified pursuant to N.J.A.C. 7:27-1.39 by the responsible official. Forms provided by the Department can be found on the Department's web site at the following link: http://www.nj.gov/dep/enforcement/compliancecertsair.htm [N.J.A.C. 7:27-22]
14	No person shall combust used oil except as authorized pursuant to N.J.A.C. 7:27-20. [N.J.A.C. 7:27-20.2]	None.	None.	Comply with the requirement: Prior to occurrence of event (prior to burning used oil) either register with the Department pursuant to N.J.A.C. 7:27-20.3 or obtain a permit issued by the Department pursuant to N.J.A.C. 7:27-8 or 7:27-22, whichever is applicable. [N.J.A.C. 7:27-20.2(d)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
15	Prevention of Accidental Releases: Facilities producing, processing, handling or storing a chemical, listed in the tables of 40 CFR Part 68.130, and present in a process in a quantity greater than the listed Threshold Quantity, shall comply with 40 CFR 68. [40 CFR 68]	Other: Comply with 40 CFR 68. [40 CFR 68].	Other: Comply with 40 CFR 68. [40 CFR 68].	Other (provide description): Other. Comply with 40 CFR 68 as described in the Applicable Requirement. [40 CFR 68]
16	For equipment subject to CO2 Budget Trading Program, comply with N.J.A.C. 7:27C. [N.J.A.C. 7:27C]	Other: See N.J.A.C. 7:27C. [N.J.A.C. 7:27C].	Other: See N.J.A.C. 7:27C. [N.J.A.C. 7:27C].	Comply with the requirement: Upon occurrence of event. [N.J.A.C. 7:27C]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Subject Item: **GR1 Combustion Turbines with Duct Burning**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	TSP <= 90.32 tons/yr. [N.J.A.C. 7:27-22.16(a)]	TSP: Monitored by calculations annually, based on a 12 calendar month average [N.J.A.C. 7:27-22.16(a)]	TSP: Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(a)]	
2	VOC (Total) <= 35.5 tons/yr. [N.J.A.C. 7:27-22.16(a)]	VOC (Total): Monitored by calculations annually, based on a 12 calendar month average [N.J.A.C. 7:27-22.16(a)]	VOC (Total): Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(a)]	
3	NOx (Total) <= 142.1 tons/yr. [N.J.A.C. 7:27-22.16(a)]	NOx (Total): Monitored by calculations annually, based on a 12 calendar month average [N.J.A.C. 7:27-22.16(a)]	NOx (Total): Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(a)]	
4	CO <= 484.7 tons/yr. [N.J.A.C. 7:27-22.16(a)]	CO: Monitored by calculations annually, based on a 12 calendar month average [N.J.A.C. 7:27-22.16(a)]	CO: Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(a)]	
5	SO2 <= 6.2 tons/yr. [N.J.A.C. 7:27-22.16(a)]	SO2: Monitored by calculations annually, based on a 12 calendar month average [N.J.A.C. 7:27-22.16(a)]	SO2: Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(a)]	
6	Total HAPs <= 8.41 tons/yr. [N.J.A.C. 7:27-22.16(a)]	Total HAPs: Monitored by calculations annually, based on a 12 calendar month average [N.J.A.C. 7:27-22.16(a)]	Total HAPs: Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(a)]	
7	PM-10 (Total) <= 90.32 tons/yr. [N.J.A.C. 7:27-22.16(a)]	PM-10 (Total): Monitored by calculations annually, based on a 12 calendar month period. [N.J.A.C. 7:27-22.16(a)]	PM-10 (Total): Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(a)]	
8	PM-2.5 (Total) <= 90.32 tons/yr. [N.J.A.C. 7:27-22.16(a)]	PM-2.5 (Total): Monitored by calculations annually, based on a 12 calendar month period. [N.J.A.C. 7:27-22.16(a)]	PM-2.5 (Total): Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(a)]	

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U1 2 Turbines, 2 HRSGs, and Aux. Boiler**

Operating Scenario: **OS Summary**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	TSP <= 90.32 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
2	PM-10 (Total) <= 90.32 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
3	VOC (Total) <= 35.63 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
4	NOx (Total) <= 142.63 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
5	CO <= 485.68 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
6	SO2 <= 6.2 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
7	HAPs (Total): <= 8.41 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
8	PM-2.5 (Total) <= 90.32 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
9	NOx (Total) <= 15 ppmvd @ 15% O2. This limit applies to a turbine that has heat input at peak load greater than 850 MMBtu/hr (HHV) firing natural gas and commenced construction, modification or reconstruction after February 18, 2005. [40 CFR 60.4320(a)]	NOx (Total): Monitored by stack emission testing at the approved frequency, based on the average of three Department validated stack test runs. The owner or operator shall conduct an initial performance test as required in 40 CFR 60.8. The subsequent testing shall only be conducted if choosing to comply with 40 CFR 60.4340(a). Test methods and procedures shall be consistent with the requirements of 40 CFR 60.4400 or, if a NOx diluent CEMS is installed, consistent with 40 CFR 60.4405. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Alternatively, the testing might be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. For turbines with supplemental duct burner NOx measurements shall be taken after the duct burner, which has to be in operation during the performance test. [40 CFR 60.4400]	NOx (Total): Recordkeeping by stack test results at the approved frequency. [40 CFR 60.4460]	Submit a report: As per the approved schedule. The owner or operator shall submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test. [40 CFR 60.4375(b)]

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
10	NOx (Total) <= 0.43 lb/MW-hr of useful output. This limit applies to a turbine that has heat input at peak load greater than 850 MMBtu/hr (HHV) firing natural gas and commenced construction, modification or reconstruction after February 18, 2005. [40 CFR 60.4320(a)]	NOx (Total): Monitored by stack emission testing at the approved frequency, based on the average of three Department validated stack test runs. The owner or operator shall conduct an initial performance test as required in 40 CFR 60.8. The subsequent testing shall only be conducted if choosing to comply with 40 CFR 60.4340(a). Test methods and procedures shall be consistent with the requirements of 40 CFR 60.4400 or, if a NOx diluent CEMS is installed, consistent with 40 CFR 60.4405. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Alternatively, the testing might be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. For turbines with supplemental duct burner NOx measurements shall be taken after the duct burner, which has to be in operation during the performance test. [40 CFR 60.4400]	NOx (Total): Recordkeeping by stack test results at the approved frequency. [40 CFR 60.4460]	Submit a report: As per the approved schedule. The owner or operator shall submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test. [40 CFR 60.4375(b)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
11	NOx (Total) <= 96 ppmvd @ 15% O2. This limit applies to a turbine that has output greater than 30 MW and whether turbine operating at less than 75 percent of peak load or turbine operating at temperature less than 0 degrees F. [40 CFR 60.4320(a)]	NOx (Total): Monitored by stack emission testing at the approved frequency, based on the average of three Department validated stack test runs. The owner or operator shall conduct an initial performance test as required in 40 CFR 60.8. The subsequent testing shall only be conducted if choosing to comply with 40 CFR 60.4340(a). Test methods and procedures shall be consistent with the requirements of 40 CFR 60.4400 or, if a NOx diluent CEMS is installed, consistent with 40 CFR 60.4405. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Alternatively, the testing might be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. For turbines with supplemental duct burner NOx measurements shall be taken after the duct burner, which has to be in operation during the performance test. [40 CFR 60.4400]	NOx (Total): Recordkeeping by stack test results at the approved frequency. [40 CFR 60.4460]	Submit a report: As per the approved schedule. The owner or operator shall submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test. [40 CFR 60.4375(b)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
12	NOx (Total) <= 4.7 lb/MW-hr of useful output. This limit applies to a turbine that has output greater than 30 MW and whether turbine operating at less than 75 percent of peak load or turbine operating at temperature less than 0 degrees F. [40 CFR 60.4320(a)]	NOx (Total): Monitored by stack emission testing at the approved frequency, based on the average of three Department validated stack test runs. The owner or operator shall conduct an initial performance test as required in 40 CFR 60.8. The subsequent testing shall only be conducted if choosing to comply with 40 CFR 60.4340(a). Test methods and procedures shall be consistent with the requirements of 40 CFR 60.4400 or, if a NOx diluent CEMS is installed, consistent with 40 CFR 60.4405. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Alternatively, the testing might be performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. For turbines with supplemental duct burner NOx measurements shall be taken after the duct burner, which has to be in operation during the performance test. [40 CFR 60.4400]	NOx (Total): Recordkeeping by stack test results at the approved frequency. [40 CFR 60.4460]	Submit a report: As per the approved schedule. The owner or operator shall submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test. [40 CFR 60.4375(b)]
13	No owner or operator shall cause to be discharged into the atmosphere, any gases which contain sulfur dioxide in excess of SO2 <= 0.9 lb/MW-hr. [40 CFR 60.4330(a)(1)]	SO2: Monitored by stack emission testing at the approved frequency, based on the average of three Department validated stack test runs. Test methods and procedures shall be consistent with 40 CFR 60.4415(a)(2) or 60.4415(a)(3). [40 CFR 60.4360]	SO2: Recordkeeping by stack test results at the approved frequency. [40 CFR 60.4415]	Submit a report: As per the approved schedule. The owner or operator shall submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test. [40 CFR 60.4375(b)]
14	SO2 <= 0.06 lb/MMBTU. No owner or operator shall burn any fuel which contains total potential sulfur emissions in excess of specified limit. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement. [40 CFR 60.4330(a)(2)]	SO2: Monitored by grab sampling once initially. Test methods and procedures shall be consistent with 40 CFR 60.4415(a)(1). The fuel analyses may be performed by the owner or operator, the fuel vendor, or any other qualified agency. [40 CFR 60.4360]	None.	Submit a report: Once initially. The permittee shall furnish the Administrator and NJDEP a written report of the results of fuel analyses. The permittee shall demonstrate that the potential sulfur emissions from each type of fuel do not exceed potential sulfur emissions of 0.060 lb SO2 per MMBtu heat input. [40 CFR 60.8(a)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
15	SO2 <= 0.06 lb/MMBTU. No owner or operator shall burn any fuel which contains total potential sulfur emissions in excess of specified limit. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement. [40 CFR 60.4330(a)(2)]	Other: The permittee shall demonstrate that the potential sulfur emissions from each type of fuel do not exceed potential sulfur emissions of 0.060 lb SO2 per MMBtu heat input using sources of information listed in 40 CFR 60.4365(a) or perform representative fuel sampling as described in 60.4365(b). [40 CFR 60.4365].	None.	Submit documentation of compliance: Once initially. The permittee shall furnish the Administrator and NJDEP a written report of the results. The permittee shall demonstrate that the potential sulfur emissions from each type of fuel do not exceed potential sulfur emissions of 0.060 lb SO2 per MMBtu heat input using sources of information listed in 40 CFR 60.4365(a) or perform representative fuel sampling as described in 60.4365(b). [40 CFR 60.8(a)]
16	The owner or operator shall operate and maintain the subject stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown and malfunction. [40 CFR 60.4333(a)]	None.	None.	None.
17	To demonstrate continuous compliance with NOx limit, the owner or operator of the turbine that does not use water or steam injection may, as alternative to performing annual performance tests as described in 40 CFR 60.4340(a), install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor and a diluent gas O2 or CO2 monitors to determine the hourly NOx emission rate in ppm or lb/MMBtu as described in 40 CFR 60.4335(b) and 60.4345. [40 CFR 60.4340(b)(1)]	Monitored by continuous emission monitoring system continuously. The continuous emission monitoring system as described in 40 CFR 60.4335(b) shall be consistent with the requirements of 40 CFR 60.4335(b) and 40 CFR 60.4345. [40 CFR 60.4345]	Recordkeeping by data acquisition system (DAS) / electronic data storage continuously. [40 CFR 60.4345]	None.
18	The permittee shall install and certify each NOx diluent CEMS in accordance with Performance Specifications 2 (PS2) as described in appendix B to 40 CFR 60. The 7 day calibration drift should be based on unit operating days, not calendar days. Upon the Bureau of Technical Services of NJDEP approval, Procedure 1 in appendix F to 40 CFR 60 is not required. The relative accuracy test audit (RATA) shall be performed on a lb/MMBtu basis. [40 CFR 60.4345(a)]	Monitored by continuous emission monitoring system continuously. During each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (Sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour, as specified in 40 CFR 60.13(e)(2). The permittee shall follow procedure described in 40 CFR 60.4345(b) for partial unit operating hours. [40 CFR 60.4345(b)]	Recordkeeping by manual logging of parameter or storing data in a computer data system once initially. The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment. For NOx CEMS and fuel flow meters, the QA program and plan described in section 1 of appendix B to 40 CFR 75 may, with state approval, satisfy this requirement. [40 CFR 60.4345(e)]	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
19	The permittee shall install and certify a NOx diluent CEMS in accordance with appendix A to 40 CFR 75. The relative accuracy test audit (RATA) shall be performed on a lb/MMBtu basis. [40 CFR 60.4345(a)]	Monitored by continuous emission monitoring system continuously. During each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (Sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour, as specified in 40 CFR 60.13(e)(2). The permittee shall follow procedure described in 40 CFR 60.4345(b) for partial unit operating hours. [40 CFR 60.4345(b)]	Recordkeeping by manual logging of parameter or storing data in a computer data system once initially. The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment. For NOx CEMS and fuel flow meters, the QA program and plan described in section 1 of appendix B to 40 CFR 75 may, with state approval, satisfy this requirement. [40 CFR 60.4345(e)]	None.
20	The permittee shall install, calibrate, maintain, and operate each fuel flowmeter in accordance with the manufacturer's instructions or, with NJDEP approval, in accordance with the requirements of appendix D to 40 CFR 75. [40 CFR 60.4345(c)]	Monitored by fuel flow/firing rate instrument continuously. Each fuel flowmeter shall be installed, calibrated, maintained and operated according to the manufacturer's instructions. Alternatively, with the NJDEP approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to 40 CFR 75 are acceptable. [40 CFR 60.4345(c)]	Recordkeeping by manual logging of parameter or storing data in a computer data system once initially. The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment. For NOx CEMS and fuel flow meters, the QA program and plan described in section 1 of appendix B to 40 CFR 75 may, with state approval, satisfy this requirement. [40 CFR 60.4345(e)]	None.
21	The permittee shall install, calibrate, maintain, and operate each watt meter, steam flow meter, and each pressure or temperature measurement device in accordance with the manufacturer's instructions. [40 CFR 60.4345(d)]	Monitored by other method (provide description) continuously. The gross electrical output of the unit in megawatt-hours shall be monitored by watt meter (or (meters) and shall be installed, calibrated, maintained and operated according to the manufacturer's instructions. [40 CFR 60.4345(d)]	Recordkeeping by manual logging of parameter or storing data in a computer data system once initially. The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment. [40 CFR 60.4345(e)]	None.
22	The owner or operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO2/MMBtu heat input for units located in continental areas. [40 CFR 60.4365]	Other: The required demonstration that the total sulfur content of the fuel does not exceed potential sulfur emissions of 0.060 lb SO2/MMBtu shall be made using a current valid purchase contract, tariff sheet or transportation contract specifying that in continental areas the maximum total sulfur content for oil use is 0.05 weight percent (500 ppmw) and for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet. [40 CFR 60.4365(a)].	Recordkeeping by fuel certification receipts at the approved frequency The owner or operator shall keep copies of valid purchase contracts, tariff sheets or transportation contracts specifying that in continental areas the maximum total sulfur content for oil use is 0.05 weight percent (500 ppmw) and for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet. [40 CFR 60.4365]	Demonstrate compliance: Once initially. The owner or operator shall submit the required determination to the Administrator using the sources of information described in 40 CFR 60.4365(a) showing the maximum total sulfur content for continental areas for oil use at 0.05 weight percent or less and for natural gas at 20 grains of sulfur or less per 100 standard cubic feet or to demonstrate that fuel has potential sulfur emissions of less than 0.060 lb SO2 /MMBtu heat input. [40 CFR 60.4365(a)]

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
23	The owner or operator shall submit reports of excess emissions and monitor downtime in accordance with 40 CFR 60.7(c) for Nitrogen oxides. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. An excess emissions as defined in 40 CFR 60.4380(b)1 is any unit operating period in which the 4-hour (for simple cycle turbines) or 30-day rolling average NOx emission rate exceeds the applicable emission limit in 40 CFR 60.4320. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NOx concentration, CO2 or O2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if used for compliance demonstration. [40 CFR 60.4380(b)]	Other: For the purposes of identifying excess emissions based on data from the continuous emission monitoring equipment the permittee shall follow procedures described in 40 CFR 60.4350(a), (b), (c), (e), (f), (g), and (h). If a NOx diluent CEMS meets the requirements of 40 CFR 75, the only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in subpart D of 40 CFR 75 are applied are to be reported as monitor downtime. [40 CFR 60.4350].	None.	Submit an Excess Emissions and Monitoring Systems Performance Report (EEMPR): Semi-annually beginning on the 30th day of the 6th month following initial performance tests. All reports required under 40 CFR 60.7(c) must be postmarked by the 30th day following the end of each 6-moth period. [40 CFR 60.4395]
24	All requests, reports, applications, submittals, and other communications to the Administrator pursuant to Part 60 shall be submitted in duplicate to the Regional Office of US Environmental Protection Agency. Submit information to: Director, Division of Enforcement & Compliance Assistance, US EPA, Region 2, 290 Broadway, New York, NY 10007-1866. [40 CFR 60.4(a)]	None.	None.	Submit a report: As per the approved schedule to EPA Region 2 as required by 40 CFR 60. [40 CFR 60.4(a)]
25	Copies of all information submitted to EPA pursuant to 40 CFR Part 60, must also be submitted to the appropriate Regional Enforcement Office of NJDEP. [40 CFR 60.4(b)]	None.	None.	Submit a report: As per the approved schedule to the appropriate Regional Enforcement Office of NJDEP as required by 40 CFR 60. [40 CFR 60.4(b)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
26	The owner or operator subject to the provisions of 40 CFR Part 60 shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, of the date of construction or reconstruction of an affected facility as defined under 40 CFR Part 60 Subpart A. Notification shall be postmarked no later than 30 days after such date. [40 CFR 60.7(a)(1)]	None.	None.	Submit notification: Upon occurrence of event to EPA Region 2 and the appropriate Regional Enforcement Office of NJDEP as required by 40 CFR 60.7 [40 CFR 60.7(a)(1)]
27	The owner or operator subject to the provisions of 40 CFR Part 60 shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, of the actual date of initial startup of an affected facility postmarked within 15 days after such date. [40 CFR 60.7(a)(3)]	None.	None.	Submit notification: Upon occurrence of event to EPA Region 2 and the appropriate Regional Enforcement Office of NJDEP as required by 40 CFR 60.7 [40 CFR 60.7(a)(3)]
28	The owner or operator subject to the provisions of 40 CFR Part 60 shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in section 60.14(e). The notification shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of facility before and after the change and the expected completion date of the change. Notification shall be postmarked within 60 days or as soon as practicable before any change is commenced. The Administrator may request additional relevant information subsequent to this notice. [40 CFR 60.7(a)(4)]	None.	None.	Submit notification: Upon occurrence of event to EPA Region 2 and the appropriate Regional Enforcement Office of NJDEP as required by 40 CFR 60.7 [40 CFR 60.7(a)(4)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
29	The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility, any malfunction of air pollution control equipment or any periods during which continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]	None.	Recordkeeping by manual logging of parameter or storing data in a computer data system upon occurrence of event. The records should be kept in a permanent form suitable for inspections. [40 CFR 60.7(b)]	Submit an Excess Emissions and Monitoring Systems Performance Report (EEMPR): Semi-annually beginning on the 30th day of the 6th month following initial performance tests. The report shall contain the information required in 40 CFR 60.7(b) and be postmarked by the 30th day following the end of each six-month period. The report shall be submitted to the EPA Region 2 Administrator and the appropriate Regional Enforcement Office of NJDEP and be in the format specified at 40 CFR Part 60.7(c) and 40 CFR Part 60.7(d). [40 CFR 60.7(c)]
30	Each owner or operator required to install a continuous monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see section 60.7(d)) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. [40 CFR 60.7(c)]	None.	Other: Written reports of excess emissions shall include the following information: (1) The magnitude of excess emissions computed in accordance with section 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period and excess emissions. The process operating time during the reporting period. (2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. (3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. (4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report. [40 CFR 60.7(c)].	Submit an Excess Emissions and Monitoring Systems Performance Report (EEMPR): Semi-annually beginning on the 30th day of the 6th month following initial performance tests. The report shall be postmarked by the 30th day following the end of each six-month period. The report shall be submitted to the EPA Region 2 Administrator and the appropriate Regional Enforcement Office of NJDEP and be in the format specified at 40 CFR Part 60.7(c) and 40 CFR Part 60.7(d). [40 CFR 60.7(c)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
31	The owner or operator shall maintain a file, suitable for inspection, of all monitoring measurements as indicated in Recordkeeping Requirement column. [40 CFR 60.7(f)]	None.	Other: The file shall include all measurements (including continuous monitoring system, monitoring device, and performance testing measurements), all continuous monitoring system performance evaluations, all continuous monitoring system or monitoring device calibration checks, all adjustments/maintenance performed on these systems or devices, and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the dates of the record, except as prescribed in 40 CFR 60.7(f)(1) through (3). Sources subject to 40 CFR 70, are required to retain records of all required monitoring data and support information for a period of at least 5 years from the date of the monitoring sample, measurement, report, or application, per 40 CFR 70.6(a)(3)(ii)(B). [40 CFR 60.7(f)].	None.
32	Compliance with NSPS standards specified in this permit, other than opacity, shall be determined only by performance tests established by 40 CFR 60.8, unless otherwise specified in NSPS. [40 CFR 60.11(a)]	None.	None.	None.
33	The owner or operator shall demonstrate compliance with NSPS opacity standards specified in 40 CFR Part 60. [40 CFR 60.11(b)]	Monitored by continuous opacity monitoring system continuously, based on 6 minute blocks. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours for the performance test. [40 CFR 60.11(b)]	Recordkeeping by strip chart or data acquisition (DAS) system continuously. [40 CFR 60.13(h)]	Submit a report: At a common schedule agreed upon by the operator and the Administrator. The owner or operator shall submit Continuous Opacity Monitoring System (COMS) data produced during any performance test in lieu of Method 9 data. The owner or operator shall notify the Administrator in writing of intent to demonstrate compliance using COMS data at least 30 days before any performance required under 40CFR Part 60.8 is conducted and shall follow procedures outlined in 40CFR Part 60.11(e). [40 CFR 60.11(e)(5)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
34	The owner or operator shall record the monitoring data produced during the initial performance test as required by 40 CFR Part 60.8. [40 CFR 60.11(e)(4)]	None.	None.	Submit a report: At a common schedule agreed upon by the operator and the Administrator. The owner or operator shall submit continuous opacity monitoring results along with Method 9 and 40 CFR 60.8 performance test results. [40 CFR 60.11(e)(4)]
35	For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in 40 CFR Part 60.8. If no performance test is required to be performed, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. [40 CFR 60.11(e)(1)]	None.	None.	Submit notification: As per the approved schedule. The owner or operator shall notify the Administrator of the anticipated date for conducting the opacity observation. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during the performance test. The notification shall be postmarked not less than 30 days prior to such a date. [40 CFR 60.7(a)(6)]
36	The NSPS opacity standard shall apply at all times except during periods of startup, shutdown, malfunctions and as otherwise specified in this permit. [40 CFR 60.11(c)]	None.	None.	None.
37	At all times, including periods of start-up, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source. [40 CFR 60.11(d)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
38	No owner or operator subject to NSPS standards in Part 60, shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]	None.	None.	None.
39	All continuous opacity monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests specified under 40 CFR Part 60.8. The owner or operator shall follow manufacturer's written recommendations for installation, operation and calibration of the device. [40 CFR 60.13(b)]	Before the performance test required under 40 CFR Part 60.8 is conducted, the owner or operator shall conduct a performance evaluation of continuous opacity monitoring system as specified in Performance Specification 1, Appendix B of 40CFR60. Monitored by other method (provide description) upon occurrence of event. [40 CFR 60.13(c)]	None.	At least 10 days before conducting the performance test, furnish the Administrator two or, upon request, more copies of the results of the performance evaluation. Submit a report: As per the approved schedule. [40 CFR 60.13(c)(1)]
40	All continuous opacity monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests specified under 40 CFR Part 60.8. The owner or operator shall follow manufacturer's written recommendations for installation, operation and calibration of the device. [40 CFR 60.13(b)]	During any performance test required under 40 CFR Part 60.8 or within 30 days thereafter, the owner or operator shall conduct a performance evaluation of the continuous opacity monitoring system in accordance with applicable performance specification in Appendix B of 40 CFR Part 60. Monitored by other method (provide description) upon occurrence of event. [40 CFR 60.13(c)]	None.	Within 60 days of completion of the performance test, furnish the Administrator two or, upon request, more copies of the results of the performance evaluation. Submit a report: As per the approved schedule. [40 CFR 60.13(c)(2)]
41	All continuous emission monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests specified under 40 CFR Part 60.8. The owner or operator shall follow manufacturer's written recommendations for installation, operation and calibration of the device. [40 CFR 60.13(b)]	During any performance test required under 40 CFR Part 60.8 or within 30 days thereafter, the owner or operator shall conduct a performance evaluation of the continuous emission monitoring system in accordance with applicable performance specification in Appendix B of 40 CFR Part 60. Monitored by other method (provide description) upon occurrence of event. [40 CFR 60.13(c)]	None.	Within 60 days of completion of the performance test, furnish the Administrator two or, upon request, more copies of the results of the performance evaluation. Submit a report: As per the approved schedule. [40 CFR 60.13(c)(2)]

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
42	The owner or operator shall perform zero and span adjustments daily for continuous emission monitors and continuous opacity monitors following procedures outlined in 40 CFR Part 60.13(d)1 & 2. [40 CFR 60.13(d)]	None.	Other: Maintain records in accordance with 40 CFR 60.7(f). [40 CFR 60.13(d)].	None.
43	Except for system breakdowns, repairs, calibration checks, and zero and span adjustments, all continuous opacity monitoring systems referenced by 40 CFR 60.13(c) shall be in continuous operation. They shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. [40 CFR 60.13(e)(1)]	Other: See Applicable Requirement. [40 CFR 60.13(e)(1)].	Other: See Applicable Requirement. [40 CFR 60.13(e)(1)].	None.
44	Except for system breakdowns, repairs, calibration checks, and zero and span adjustments, all continuous monitoring systems referenced by 40 CFR 60.13(c) measuring emissions except opacity shall be in continuous operation. They shall complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period. [40 CFR 60.13(e)(2)]	Other: See Applicable Requirement. [40 CFR 60.13(e)(2)].	Other: See Applicable Requirement. [40 CFR 60.13(e)(2)].	None.
45	All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of Appendix B of 40 CFR Part 60 shall be used. [40 CFR 60.13(f)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
46	The owner or operator of all continuous monitoring systems for measuring opacity shall reduce all data to 6-minute averages which shall be calculated from 36 or more data points equally spaced over each 6-minute period. Six -minute period is defined in 40 CFR 60.2 as any one of the 10 equal parts of a one-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. For owners and operators complying with the requirements in 40 CFR 60.7(f)(1) or (2), data averages must include any data recorded during periods of monitor breakdown or malfunction. [40 CFR 60.13(h)(1)]	None.	Other: See Applicable Requirement. [40 CFR 60.13(h)].	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
47	The owner or operator of all continuous monitoring systems (other than opacity) shall reduce all data to 1-hour averages for time periods. One-hour period is defined in 40 CFR 60.2 as any 60-minute period commencing on the hour. For a full operating hour, 1-hour averages shall be computed from at least four valid data points, i.e., one data point in each of the 15-minute quadrants of the hour. For a partial operating hour (any clock hour with less than 60 minutes of unit operation), the owner or operator shall follow all the procedures specified at 40 CFR 60.13(h)(2) to compute 1-hour averages. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. The owners and operators complying with the requirements in 40 CFR 60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages. Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). [40 CFR 60.13(h)(2)]	None.	Other: See Applicable Requirement. [40 CFR 60.13(h)].	None.
48	All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subpart to specify the emission limit. [40 CFR 60.13(h)(3)]	None.	None.	None.
49	Upon modifications, emission rates for an affected facility shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard applies. [40 CFR 60.14(b)]	None.	None.	None.

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
50	The provisions set forth under an applicable subparts of 40 CFR Part 60 supersede conflicting provisions listed under Modification in 40 CFR Part 60.14. [40 CFR 60.14(f)]	None.	None.	None.
51	Compliance with all applicable standards must be achieved within 180 days of completion of any physical or operational change subject to the control measures specified in 40 CFR Part 60.14(a). [40 CFR 60.14(g)]	None.	None.	None.
52	The owner or operator shall notify the Administrator of the proposed replacement of components. [40 CFR 60.15]	None.	None.	Submit notification: At a common schedule agreed upon by the operator and the Administrator. The notification shall include information listed under 40 CFR Part 60.15(d). The notification shall be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced. [40 CFR 60.15(d)]
53	Applicable subpart in 40 CFR Part 60 includes specific provisions which refine and delimit reconstruction as defined in 40 CFR Part 60.15. [40 CFR 60.15(g)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
54	The permittee shall submit a stack test protocol for the turbines to the Department for review and approval. The stack test shall be conducted for the following air pollutants NOx, CO, VOC, PM-10, and PM2.5 for the Equipment E1 and E2 for the following operating scenarios OS1 and OS2 and GR1 (turbine operation with and without duct burning). Testing must be conducted at worst-case permitted operating conditions with regard to meeting the applicable emission standards, but without creating an unsafe condition. The permittee shall provide BTS with the turbine load performance curve with the protocol. For a turbine subject to NSPS KKKK, the performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Alternatively, the testing might be performed at the highest achievable level point, if at least 75 percent of peak load cannot be achieved in practice. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Submit a stack test protocol: As per the approved schedule. Within 60 days from the date of initial operation of the turbines to the Department for review and approval. [N.J.A.C. 7:27-22.16(e)]
55	The permittee shall conduct a stack test for the turbines using a protocol approved by the Department. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Conduct a stack test: As per the approved schedule. Within 30 days of protocol approval, the permittee shall contact the Bureau of Technical Services at (609)530-4041 to schedule a mutually acceptable test date. The permittee shall conduct the stack test no later than 90 days from the date of approval of the stack test protocol by the Department. [N.J.A.C. 7:27-22.18(e)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
56	The permittee shall submit the results of any required stack test for the turbines to the Department for review and approval. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Submit a stack test report: As per the approved schedule to the Department for review and approval. A full stack test report must be submitted to BTS and a certified summary test report, as described in the protocol, must be submitted to the Regional Enforcement Office within 45 days from the date of testing (or later if approved by BTS before this permit is approved - provide the approved number of days if applicable). The test results must be certified by a licensed professional engineer or certified industrial hygienist. A copy of the test results must be submitted with the operating permit renewal application due at least 12 months prior to expiration of the Operating Permit. [N.J.A.C. 7:27-22.18(e)]
57	The permittee shall submit a stack test protocol for the turbines to the Department for review and approval. The stack test shall be conducted for the following air pollutants CO, NOx, VOC, PM-10, and PM2.5 for the Equipment E1 and E2 for the following operating scenarios OS1, OS2, and GR1 (turbine operation with and without duct burning). Testing must be conducted at worst-case permitted operating conditions with regard to meeting the applicable emission standards, but without creating an unsafe condition. The permittee shall provide BTS with the turbine load performance curve with the protocol. For a turbine subject to NSPS KKKK, the performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Alternatively, the testing might be performed at the highest achievable level point, if at least 75 percent of peak load cannot be achieved in practice. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Submit a stack test protocol: As per the approved schedule to the Department for review and approval. At least 30 months prior to the expiration of the approved initial or renewed operating permit the permittee shall submit a stack test protocol to the Bureau of Technical Services (BTS). [N.J.A.C. 7:27-22.16(e)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
58	The permittee shall conduct a stack test at least 18 months prior to the expiration of the approved initial or renewed operating permit using a protocol approved by the Department. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Conduct a stack test: As per the approved schedule. Within 30 days of protocol approval, the permittee shall contact the Bureau of Technical Services at (609)530-4041 to schedule a mutually acceptable test date. [N.J.A.C. 7:27-22.18(e)]
59	The permittee shall submit the results of any required stack test to the Department for review and approval. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Submit a stack test report: As per the approved schedule to the Department for review and approval. A full stack test report must be submitted to BTS and a certified summary test report, as described in the protocol, must be submitted to the Regional Enforcement Office within 45 days from the date of testing (or later if approved by BTS before this permit is approved - provide the approved number of days if applicable). The test results must be certified by a licensed professional engineer or certified industrial hygienist. A copy of the test results must be submitted with the operating permit renewal application due at least 12 months prior to expiration of the Operating Permit. [N.J.A.C. 7:27-22.18(e)]
60	The permittee shall submit a stack test protocol for the boiler to the Department for review and approval. The stack test shall be conducted for the following air pollutants CO, NOx, VOC, PM-10, and PM2.5 for the Equipment E5 for the following operating scenarios OS5. Testing must be conducted at worst-case permitted operating conditions with regard to meeting the applicable emission standards, but without creating an unsafe condition. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Submit a stack test protocol: As per the approved schedule. Within 60 days of initial startup of the boiler to the Department for review and approval. [N.J.A.C. 7:27-22.16(e)]
61	The permittee shall conduct a stack test for the boiler using a protocol approved by the Department. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Conduct a stack test: As per the approved schedule. Within 30 days of protocol approval, the permittee shall contact the Bureau of Technical Services at (609)530-4041 to schedule a mutually acceptable test date. The permittee shall conduct the stack test no later than 90 days from the date of approval of the stack test protocol by the Department. [N.J.A.C. 7:27-22.18(e)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
62	The permittee shall submit the results of any required stack test for the boiler to the Department for review and approval. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Submit a stack test report: At no specified schedule to the Department for review and approval. A full stack test report must be submitted to BTS and a certified summary test report, as described in the protocol, must be submitted to the Regional Enforcement Office within 45 days from the date of testing (or later if approved by BTS before this permit is approved - provide the approved number of days if applicable). The test results must be certified by a licensed professional engineer or certified industrial hygienist. A copy of the test results must be submitted with the operating permit renewal application due at least 12 months prior to expiration of the Operating Permit. [N.J.A.C. 7:27-22.18(e)]
63	The permittee shall submit a stack test protocol for the boiler to the Department for review and approval. The stack test shall be conducted for the following air pollutants CO, NOx, VOC, PM-10, and PM2.5 for the Equipment E5 for the following operating scenarios OS5. Testing must be conducted at worst-case permitted operating conditions with regard to meeting the applicable emission standards, but without creating an unsafe condition. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Submit a stack test protocol: As per the approved schedule to the Department for review and approval. At least 30 months prior to the expiration of the approved initial or renewed operating permit the permittee shall submit a stack test protocol to the Bureau of Technical Services (BTS). [N.J.A.C. 7:27-22.16(e)]
64	The permittee shall conduct a stack test at least 18 months prior to the expiration of the approved initial or renewed operating permit using a protocol approved by the Department. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Conduct a stack test: As per the approved schedule. Within 30 days of protocol approval, the permittee shall contact the Bureau of Technical Services at (609)530-4041 to schedule a mutually acceptable test date. [N.J.A.C. 7:27-22.18(e)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
65	The permittee shall submit the results of any required stack test to the Department for review and approval. [N.J.A.C. 7:27-22.16(e)]	None.	None.	Submit a stack test report: As per the approved schedule to the Department for review and approval. A full stack test report must be submitted to BTS and a certified summary test report, as described in the protocol, must be submitted to the Regional Enforcement Office within 45 days from the date of testing (or later if approved by BTS before this permit is approved - provide the approved number of days if applicable). The test results must be certified by a licensed professional engineer or certified industrial hygienist. A copy of the test results must be submitted with the operating permit renewal application due at least 12 months prior to expiration of the Operating Permit. [N.J.A.C. 7:27-22.18(e)]
66	All N.J.A.C. 7:27-22.16(a) emission limits specified in this permit for the turbines are not applicable during startup, shutdown, and during the initial startup and shakedown periods for each turbine separately. Shakedown period shall be defined as the period from initial startup until CEMS is certified by the Department. Shakedown period shall not exceed 180 calendar days from the initial firing of the turbines [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
67	The SCRS (CD101 and CD201) shall be operated at all times that the turbine is operating except during startup and shutdown. [N.J.A.C. 7:27-22.16(a)]	Monitored by hour/time monitor continuously The permittee shall record the time and duration of the operation of both the SCR and the turbine. [N.J.A.C. 7:27-22.16(o)]	Recordkeeping by data acquisition system (DAS) / electronic data storage continuously The permittee shall record the time and duration of the operation of the turbine and the SCR. [N.J.A.C. 7:27-22.16(o)]	None.
68	The oxidation catalysts (CD102 and CD202) shall be operated at all times that the turbine is operating except shartup and shutdown. [N.J.A.C. 7:27-22.16(a)]	Monitored by hour/time monitor continuously The permittee shal record the time and duration of the operation of both the oxidiation catalyst and the turbine. [N.J.A.C. 7:27-22.16(o)]	Recordkeeping by data acquisition system (DAS) / electronic data storage continuously The permittee shall continuously record the time and duration of the operation of the turbine and the oxidation catalyst unit. [N.J.A.C. 7:27-22.16(o)]	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U1 2 Turbines, 2 HRSGs, and Aux. Boiler**

Operating Scenario: **OS1 Combustion Turbine 1 firing natural gas, OS2 Combustion Turbine 2 firing natural gas**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	Opacity <= 20 % , exclusive of visible condensed water vapor, except for a period of not longer than 10 consecutive seconds. [N.J.A.C. 7:27- 3.5]			
2	Particulate Emissions <= 232 lb/hr. [N.J.A.C. 7:27- 4.2(a)]	Particulate Emissions: Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27- 4.4]	Particulate Emissions: Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to Stack Testing Requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
3	TSP <= 9.9 lb/hr. [N.J.A.C. 7:27-22.16(e)]	TSP: Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27-22.16(e)]	TSP: Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to Stack Testing Requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
4	PM-10 (Total) <= 9.9 lb/hr. [N.J.A.C. 7:27-22.16(e)]	PM-10 (Total): Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27-22.16(e)]	PM-10 (Total): Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to Stack Testing Requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
5	VOC (Total) <= 2.6 lb/hr. [N.J.A.C. 7:27-22.16(e)]	VOC (Total): Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27-22.16(e)]	VOC (Total): Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to Stack Testing Requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
6	VOC (Total) <= 2 ppmvd @ 15% O2 except for periods of start-up, shutdown and fuel transfer as defined in this permit. [N.J.A.C. 7:27-22.16(e)]	VOC (Total): Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27-22.16(e)]	VOC (Total): Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to Stack Testing Requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
7	CO <= 9.2 lb/hr. [N.J.A.C. 7:27-22.16(e)]	CO: Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27-22.16(e)]	CO: Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to Stack Testing Requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
8	CO <= 2 ppmvd @ 15% O2 except for periods of start-up, shutdown and fuel transfer as defined in this permit. [N.J.A.C. 7:27-22.16(e)]	CO: Monitored by continuous emission monitor continuously, based on a 3 hour rolling average based on a 1 hour block average. [N.J.A.C. 7:27-22.16(e)]	CO: Recordkeeping by strip chart, round chart or data acquisition (DAS) system / electronic data storage continuously. [N.J.A.C. 7:27-22.16(e)]	CEM/COM - Submit equipment protocol, conduct PST test and submit results: As per the approved schedule. Refer to CEM requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
9	SO2 <= 0.69 lb/hr. [N.J.A.C. 7:27-22.16(e)]	None.	None.	None.
10	NOx (Total) <= 15.1 lb/hr. [N.J.A.C. 7:27-22.16(e)]	NOx (Total): Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27-22.16(e)]	NOx (Total): Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to Stack Testing Requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
11	NOx (Total) <= 2 ppmvd @ 15% O2 except for periods of start-up, shutdown and fuel transfer as defined in this permit. [N.J.A.C. 7:27-22.16(e)]	NOx (Total): Monitored by continuous emission monitor continuously, based on a 3 hour rolling average based on a 1 hour block average. [N.J.A.C. 7:27-22.16(e)]	NOx (Total): Recordkeeping by strip chart, round chart or data acquisition (DAS) system / electronic data storage continuously. [N.J.A.C. 7:27-22.16(e)]	CEM/COM - Submit equipment protocol, conduct PST test and submit results: As per the approved schedule. Refer to CEM requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
12	Natural Gas Usage <= 19,925 MMft^3/yr. [N.J.A.C. 7:27-22.16(e)]	Natural Gas Usage: Monitored by fuel flow/firing rate instrument continuously, based on a consecutive 365 day period (rolling 1 day basis). The permittee shall install, calibrate and maintain the monitor(s) in accordance with the manufacturer's specifications. The monitor(s) shall be ranged such that the allowable value is approximately mid-scale of the full range current/voltage output. [N.J.A.C. 7:27-22.16(e)]	Natural Gas Usage: Recordkeeping by strip chart, round chart or data acquisition (DAS) system / electronic data storage daily. [N.J.A.C. 7:27-22.16(e)]	
13	NOx (Total) <= 0.15 lb/MMBTU. [N.J.A.C. 7:27-19.5(b)]	NOx (Total): Monitored by continuous emission monitor continuously, based on a 3 hour rolling average based on a 1 hour block average. [N.J.A.C. 7:27-19.15(a)1]	NOx (Total): Recordkeeping by strip chart, round chart or data acquisition (DAS) system / electronic data storage continuously. [N.J.A.C. 7:27-19.18(a)5]	CEM/COM - Submit equipment protocol, conduct PST test and submit results: As per the approved schedule. Refer to N.J.A.C. 7:27-22.18 and 22.19 and CEM requirements specified in this permit. [N.J.A.C. 7:27-19.18(a)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U1 2 Turbines, 2 HRSGs, and Aux. Boiler**

Operating Scenario: **OS3 Heat Recovery Steam Generator (HRSG) for Turbine 1, OS4 Heat Recovery Steam Generator (HRSG) for Turbine 2**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	The duct burner cannot run independent of the turbine (See Group 1 for Specific Requirements) [N.J.A.C. 7:27-22.16(e)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U1 2 Turbines, 2 HRSGs, and Aux. Boiler**
Operating Scenario: **OS5 Auxilary Boiler**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	No visible emissions. As specified in N.J.A.C. 7:27-3.2(c), this provision does not apply to smoke which is visible for a period of time of not longer than three (3) minutes in any consecutive 30-minute period. [N.J.A.C. 7:27- 3.2(a)]			
2	Opacity <= 20 % , exclusive of visible condensed water vapor. As specified in N.J.A.C. 7:27-3.2(c), this provision does not apply to smoke which is visible for a period of time of not longer than three (3) minutes in any consecutive 30-minute period. [N.J.A.C. 7:27- 3.2(b)]			
3	Particulate Emissions <= 12.62 lb/hr. [N.J.A.C. 7:27- 4.2(a)]	None.	None.	None.
4	Particulate Emissions <= 0.66 lb/hr. [N.J.A.C. 7:27-22.16(e)]	None.	None.	None.
5	VOC (Total) <= 0.33 lb/hr. [N.J.A.C. 7:27-22.16(e)]	None.	None.	None.
6	CO <= 2.45 lb/hr. [N.J.A.C. 7:27-22.16(e)]	CO: Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27-22.16(e)]	CO: Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to stack testing requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]
7	SO2 <= 0.03 lb/hr. [N.J.A.C. 7:27-22.16(e)]	None.	None.	None.
8	NOx (Total) <= 1.32 lb/hr. [N.J.A.C. 7:27-22.16(e)]	NOx (Total): Monitored by stack emission testing once initially and every 5 years, based on any 60 minute period. [N.J.A.C. 7:27-22.16(e)]	NOx (Total): Recordkeeping by stack test results once initially and every 5 years. [N.J.A.C. 7:27-22.16(e)]	Stack Test - Submit protocol, conduct test and submit results: As per the approved schedule. Refer to stack testing requirements specified in this permit. [N.J.A.C. 7:27-22.16(e)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
9	Hours of Operation While Firing Natural Gas <= 800 hr/yr. [N.J.A.C. 7:27-22.16(e)]	Hours of Operation While Firing Natural Gas: Monitored by hour/time monitor continuously, based on a 12 calendar month average. The permittee shall install, calibrate and maintain the monitor(s) in accordance with the manufacturer's specifications. The monitor(s) shall be ranged such that the allowable value is approximately mid-scale of the full range current/voltage output. [N.J.A.C. 7:27-22.16(e)]	Hours of Operation While Firing Natural Gas: Recordkeeping by manual logging of parameter or storing data in a computer data system annually. [N.J.A.C. 7:27-22.16(e)]	
10	Natural Gas Usage <= 51.9 MMft^3/yr. [N.J.A.C. 7:27-22.16(e)]	Natural Gas Usage: Monitored by fuel flow/firing rate instrument continuously, based on a consecutive 365 day period (rolling 1 day basis). The permittee shall install, calibrate and maintain the monitor(s) in accordance with the manufacturer's specifications. The monitor(s) shall be ranged such that the allowable value is approximately mid-scale of the full range current/voltage output. [N.J.A.C. 7:27-22.16(e)]	Natural Gas Usage: Recordkeeping by strip chart, round chart or data acquisition (DAS) system / electronic data storage continuously. [N.J.A.C. 7:27-22.16(e)]	

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
11	The owner or operator of an industrial/commercial/institutional boiler or other indirect heat exchanger with a gross heat input of at least 20 million BTU per hour or greater shall adjust the combustion process annually in the same quarter of each calendar year, beginning in 2007. If a source operation was required by N.J.A.C. 7:27-16 to perform combustion adjustment prior to November 7, 2005, the owner or operator shall continue combustion adjustments in the same quarter of each calendar year. The adjustment of the combustion process shall be done in accordance with the procedure set forth at N.J.A.C. 7:27-19.16. [N.J.A.C. 7:27-16.8(c)3], [N.J.A.C. 7:27-16.8(b)3ii], and [N.J.A.C. 7:27-19.7(g)3]	Monitored by periodic emission monitoring annually. The owner or operator shall perform the adjustment of the combustion process in accordance with the specific procedures for combustion adjustment monitoring specified in NJDEP Technical Manual 1005 and the procedure set forth at N.J.A.C. 7:27-19.16(a) as follows: 1.Inspect the burner, and clean or replace any components of the burner as necessary; 2. Inspect the flame pattern and make any adjustments to the burner necessary to optimize the flame pattern consistent with the manufacturer's specifications; 3. Inspect the system controlling the air-to-fuel ratio, and ensure that it is correctly calibrated and functioning properly; 4. Minimize the total emissions of NOx and CO consistent with the manufacturer's specifications; 5. Measure the concentrations in the effluent stream of NOx, CO and O2 in ppmvd, before and after the adjustment is made; and 6. Convert the emission values of NOx, CO and O2 concentrations measured in lb/MMBTU according to the following formula: Lb/MMBTU = ppmvd * MW * F dry factor * O2 correction factor/387,000,000, where: ppmvd is the concentration in parts per million by volume, dry basis, of NOx or CO; MW is the Molecular Weight for NOx=46 lb/lb-mole, CO=28 lb/lb-mole; F Dry factor for: Natural Gas = 8,710 dscf/MMBTU, Residual or fuel oil = 9,190 dscf/MMBTU; O2 correction factor: (20.9%)/(20.9% - O2 measured), where O2 measured is percent oxygen on a dry basis. [N.J.A.C. 7:27-19.16(a)]	Recordkeeping by manual logging of parameter or storing data in a computer data system upon performing combustion adjustment of the following information for each adjustment: 1. The date of the adjustment and the times at which it began and ended; 2. The name, title and affiliation of the person whom made the adjustment; 3. The NOx and CO concentrations in the effluent stream, in ppmvd, before and after each actual adjustment was made; 4. The concentration of O2 (in percent dry basis) at which the CO and NOx concentrations were measured; 5. A description of any corrective action taken; 6. Results from any subsequent test performed after taking any corrective action, including concentrations and converted emission values in (lb/MMBTU); 7. The type and amount of fuel used over the 12 months prior to the annual adjustment; 8. Any other information which the Department or the EPA has required as a condition of approval of any permit or certificate issued for the source operation. The records must be retained for a minimum of five years and to be made readily accessible to the Department upon request. [N.J.A.C. 7:27-19.16(b)]	Submit a report: As per the approved schedule. Beginning in 2009, the owner or operator shall submit an annual adjustment combustion process report electronically to the Department within 45 days after the adjustment of the combustion process is completed. The report shall be in the format the Department specifies at its website http://www.nj.gov/dep/aqpp/adjustment.htm and shall contain the following information: 1. The concentration of NOx and CO in the effluent stream in ppmvd, and O2, in percent dry basis, measured before and after the adjustment of the combustion process; 2. The converted emission values in lb/MMBTU for the measurements taken before and after the adjustment of the combustion process; 3. A description of any corrective action taken as part of the combustion adjustment; and 4. The type and amount of fuel used over the 12 months prior to the annual adjustment. [N.J.A.C. 7:27-19.16(d)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
12	The owner or operator of the adjusted equipment or source operation shall ensure that the operating parameter settings are established and recorded after the combustion process is adjusted and that the adjusted equipment or source operation is maintained to operate consistent with the annual adjustment. [N.J.A.C. 7:27-19.16(e)]	Other: Monitored by the operating parameter settings that are established after the combustion process is adjusted in order to operate consistent with the annual adjustment. [N.J.A.C. 7:27-19.16(e)].	Other: The owner or operator shall record the operating parameter settings that are established after the combustion process is adjusted and retain until the next annual adjustment, to be made readily accessible to the Department upon request.. [N.J.A.C. 7:27-19.16(e)].	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U1 2 Turbines, 2 HRSGs, and Aux. Boiler**

Operating Scenario: **OS6 Combustion Turbine 1 start-up, OS7 Combustion Turbine 2 start-up**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	Startup Period: Startup is defined as the period of time from the initiation of the combustion turbine operation until it achieves steady-state emissions compliance. The exemption from N.J.A.C. 7:27-22.16(a) emission limits during startup shall not exceed 5 hours. [N.J.A.C. 7:27-22.16(1)]	None.	None.	None.
2	NOx (Total) <= 179 lb/hr. The 1-hour rolling NOx emissions of the Turbine may not exceed 179 lb/hr during startup. [N.J.A.C. 7:27-22.16(a)]	NOx (Total): Monitored by continuous emission monitoring system continuously, based on a rolling 1 hour average. [N.J.A.C. 7:27-22.16(o)]	NOx (Total): Recordkeeping by data acquisition system (DAS) / electronic data storage continuously. [N.J.A.C. 7:27-22.16(o)]	Submit an Excess Emissions and Monitoring Systems Performance Report (EEMPR): Every April 30, July 30, October 30, and January 30 for the preceding quarter year (the quarter years begin on January 1, April 1, July 1, and October 1) electronically through the NJDEP online EEMPR web portal. [N.J.A.C. 7:27-22.16(o)]

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U1 2 Turbines, 2 HRSGs, and Aux. Boiler**

Operating Scenario: **OS8 Combustion Turbine 1 shutdown, OS9 Combustion Turbine 2 shutdown**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	Shutdown Period <= 1 hour. Shutdown is defined as the period of time from the initiation of lowering combustion turbine power output with the intent to cease generation of electrical power output and concludes with the cessation of the combustion turbine operation. The exemption from N.J.A.C. 7:27-22.16(a) emission limits during shutdown shall not exceed 1 hour. [N.J.A.C. 7:27-22.16(1)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U2 Cooling Tower**

Operating Scenario: **OS Summary**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	TSP <= 10.03 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
2	PM-10 (Total) <= 5.52 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
3	PM-2.5 (Total) <= 2.51 tons/yr. [N.J.A.C. 7:27-22.16(a)]			

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U2 Cooling Tower**
Operating Scenario: **OS1 Cooling Tower**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	Cooling tower circulation water flow rate <= 220,870 gallons per minute (gpm), based on operating permit application. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
2	Total Dissolved Solids (TDS) concentration in the cooling tower circulating water <= 4,150 mg/liter. [N.J.A.C. 7:27-22.16(a)]	Monitored by grab sampling each month during operation for analysis of circulating water. [N.J.A.C. 7:27-22.16(o)]	Recordkeeping by manual logging of parameter or storing data in a computer data system each month during operation. Maintain records of circulating water analysis. [N.J.A.C. 7:27-22.16(o)]	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U3 1.5 MW Emergency Generator**

Operating Scenario: **OS Summary**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	TSP <= 0.03 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
2	PM-10 (Total) <= 0.03 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
3	VOC (Total) <= 0.13 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
4	NOx (Total) <= 0.93 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
5	CO <= 0.58 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
6	SO2 <= 0.001 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U3 1.5 MW Emergency Generator**

Operating Scenario: **OS1 1.5 MW Emergency Generator**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	Particulate Emissions <= 6.872 lb/hr. [N.J.A.C. 7:27- 4.2(a)]	None.	None.	None.
2	TSP <= 0.66 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
3	PM-10 (Total) <= 0.66 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
4	VOC (Total) <= 2.62 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
5	CO <= 11.56 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
6	SO2 <= 0.02 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
7	NOx (Total) <= 18.53 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
8	During operation of the emergency generator the Permittee shall not cause, suffer, allow or permit smoke the shade or appearance of which is darker than number 1 on the Ringelmann smoke chart or greater than 20 percent opacity, exclusive of visible condensed water vapor, to be emitted into the outdoor air from the combustion of fuel in any emergency generator for a period of more than 10 consecutive seconds. [N.J.A.C. 7:27- 3.5]	Monitored by visual determination annually, based on a 10 consecutive second period. [N.J.A.C. 7:27- 8.13(d)]	Recordkeeping by manual logging of parameter or storing data in a computer data system annually. All records created in a calendar year shall be maintained on site for five additional calendar years, and made available to the Department for review, upon request. [N.J.A.C. 7:27- 3.6]	Notify by phone: Upon occurrence of event. Upon occurrence of visible emissions, over the allowable amount, the Permittee shall notify the Department immediately of the event. Such notification shall be made by calling the Environmental Action Hotline at (877) 927-6337. [N.J.A.C. 7:27- 8.13(d)4]
9	The allowable emission rate for particulates from the combustion of fuel shall be based on the heat input rate to the generator. [N.J.A.C. 7:27- 4.2]	None.	None.	None.

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
10	This equipment shall not cause any air contaminant, including an air contaminant detectable by the sense of smell, to be present in the outdoor atmosphere in such quantity and duration which is, or tends to be, injurious to human health or welfare, animal or plant life or property, or would unreasonably interfere with the enjoyment of life or property, except in areas over which the owner or operator has exclusive use or occupancy. [N.J.A.C. 7:27- 5]	None.	Recordkeeping by manual logging of parameter or storing data in a computer data system upon occurrence of event. Permittee shall record in either a permanent bound log book or in readily accessible computer memories instances (date and time) when the operation of equipment has the potential to cause off-property effects. All records must be maintained on site for a minimum of 5 years. [N.J.A.C. 7:27- 8.13(d)3]	Notify by phone: Upon occurrence of event. Any operation of the equipment which may cause a release of air contaminants in a quantity or concentration which poses a potential threat to public health, welfare, or the environment or which might reasonably result in citizen complaints shall be reported by the Permittee as required by the Air Pollution Control Act. Such notification shall be made by calling the Environmental Action Hotline at (877) 927-6337. [N.J.S.A. 26:2C-19(e)]
11	Compliance with the annual emission limit for each air contaminant (NOx, VOC, CO, SO2, TSP/PM-10) shall be based on hours of operation per year used for testing and maintenance. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
12	The equipment specified in the permit shall be operated only under the following situations: (a) During the performance of normal testing and maintenance procedures, as recommended in writing by the manufacturer and/or as required in writing by a Federal or State law or regulation. (b) When there is a power outage or the facility's primary source of mechanical or thermal energy fails because of an emergency; or (c) When there is a voltage reduction issued by PJM Interconnection, LLC (PJM) and posted on the PJM internet website (www.pjm.com) under the "Emergency Procedures" menu. [N.J.A.C. 7:27-19.1]	Monitored by hour/time monitor continuously. Permittee shall install and operate a totalizing, non-resettable hour meter monitoring the total hours of operation per year for each generator. [N.J.A.C. 7:27- 8.13(d)]	Recordkeeping by manual logging of parameter or storing data in a computer data system upon occurrence of event. The owner or operator of an emergency generator shall record in a logbook or computer data system, the following information for each emergency generator: (a) Total operating time from the emergency generator's hour meter, once per month; (b) If a voltage reduction is the reason for use of the emergency generator, a copy of the voltage reduction notification from PJM or other documentation of the voltage reduction, upon occurrence of event; and (c) If testing or maintenance is the reason for the operation of the emergency generator, the Permittee shall record the following upon occurrence of event: 1.The reason for its operation. 2.The date(s) of operation and the start-up and shutdown time; 3.The total operating time for testing or maintenance based on the emergency generator's hour meter; and 4.The name of the operator. 5.The monthly hours of operation during emergency periods shall be maintained. The owner or operator of an emergency generator shall maintain the records on site for a period of no less than five years after the record was made and shall make the records readily available to the Department or the EPA, upon request. [N.J.A.C. 7:27-19.11]	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
13	Emergency generators shall not be used: 1) In a circumstance other than an emergency; for normal testing and maintenance on days when the Department forecasts air quality anywhere in New Jersey to be "unhealthy for sensitive groups," "unhealthy," or "very unhealthy" or "hazardous" unless required in writing by a Federal or State law or regulation. Procedures for determining the air quality forecasts for New Jersey are available at the Department air quality web site at http://www.state.nj.us/dep/aqpp/aqforecast ; and 2) as a source of energy or power after the primary energy or power source has become operable again. If the primary energy or power source is under the control of the owner or operator of the emergency generator, the owner or operator shall make a reasonable, timely effort to repair the primary energy or power source. [N.J.A.C. 7:27-19.2(d)]	Other: The Permittee shall check the air quality forecast for New Jersey available at the Department air quality website at http://www.state.nj.us/dep/aqpp/aqforecast prior to operating during testing and maintenance periods. [N.J.A.C. 7:27-8.13(d)].	None.	Submit a report: Upon occurrence of event. The permittee shall report any non-compliance in writing within 3 working days after the event to the Regional Enforcement Office. [N.J.A.C. 7:27-8.13(d)4]
14	The emergency generators manufactured after April 1, 2006 (if a fire pump - after July 1, 2006) or modified or reconstructed after July 11, 2005 shall use, beginning October 1, 2010, liquid fuel that contains the following per gallon standards: 15 ppm (0.0015%) maximum sulfur content and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. [40 CFR 60.4207(b)]	Monitored by review of fuel delivery records once per bulk fuel shipment. For each fuel oil delivery received, the Permitee shall review written documentation of the delivery to ensure the maximum allowable fuel oil sulfur content is not being exceeded. Such written documentation can include, but is not limited to: a bill of lading, delivery invoice, certificate of analysis. [N.J.A.C. 7:27- 8.13(d)]	Recordkeeping by invoices / bills of lading / certificate of analysis once per bulk fuel shipment. The permittee shall keep records of fuel oil sulfur content for each delivery received. All records must be maintained for a minimum of 5 years. [N.J.A.C. 7:27-8.13(d)3]	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
15	The owner or operator of an Emergency Generator(s) combusting liquid fuel in a 2007 model year and later engine (in case of a fire pump - during or after a model year that applies to the fire pump engine power rating in Table 3 of NSPS IIII) must use an engine certified to the emission standards in 60.4204(b) or 60.4205(b) or (c), as applicable, for the same model year and maximum engine power (or in case of a fire pump, the NFPA nameplate power). The engine must be installed and configured according to the manufacturer's recommendations. [40 CFR 60.4211(c)]	None.	Other: Keep documentation from the manufacturer that the engine is certified to meet the emission standards. [40 CFR 60.4214(a)2iii] and [N.J.A.C. 7:27-8.13(d)3].	None.
16	The maximum annual operating hours for normal testing and maintenance shall not exceed 100 hours/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
17	The emergency generator generator shall not be tested at the same time as the fire pump. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
18	The duration of a testing event is restricted to 30 minutes. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
19	The emergency generator shall not be tested during the startup or shutdown of the turbines or the boiler. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U4 270 HP Fire Pump**

Operating Scenario: **OS Summary**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	TSP <= 0.004 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
2	PM-10 (Total) <= 0.004 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
3	VOC (Total) <= 0.01 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
4	NOx (Total) <= 0.08 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
5	CO <= 0.08 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
6	SO2 <= 0.0001 tons/yr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Emission Unit: **U4 270 HP Fire Pump**
Operating Scenario: **OS1 270 HP Fire Pump**

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
1	Particulate Emissions <= 1.24 lb/hr. [N.J.A.C. 7:27- 4.2(a)]	None.	None.	None.
2	TSP <= 0.09 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
3	PM-10 (Total) <= 0.09 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
4	VOC (Total) <= 0.22 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
5	CO <= 1.55 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
6	SO2 <= 0.0021 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
7	NOx (Total) <= 1.55 lb/hr. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
8	During operation of the emergency generator the Permittee shall not cause, suffer, allow or permit smoke the shade or appearance of which is darker than number 1 on the Ringelmann smoke chart or greater than 20 percent opacity, exclusive of visible condensed water vapor, to be emitted into the outdoor air from the combustion of fuel in any emergency generator for a period of more than 10 consecutive seconds. [N.J.A.C. 7:27- 3.5]	Monitored by visual determination annually, based on a 10 consecutive second period. [N.J.A.C. 7:27- 8.13(d)]	Recordkeeping by manual logging of parameter or storing data in a computer data system annually. All records created in a calendar year shall be maintained on site for five additional calendar years, and made available to the Department for review, upon request. [N.J.A.C. 7:27- 3.6]	Notify by phone: Upon occurrence of event. Upon occurrence of visible emissions, over the allowable amount, the Permittee shall notify the Department immediately of the event. Such notification shall be made by calling the Environmental Action Hotline at (877) 927-6337. [N.J.A.C. 7:27- 8.13(d)4]
9	The allowable emission rate for particulates from the combustion of fuel shall be based on the heat input rate to the generator. [N.J.A.C. 7:27- 4.2]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
10	This equipment shall not cause any air contaminant, including an air contaminant detectable by the sense of smell, to be present in the outdoor atmosphere in such quantity and duration which is, or tends to be, injurious to human health or welfare, animal or plant life or property, or would unreasonably interfere with the enjoyment of life or property, except in areas over which the owner or operator has exclusive use or occupancy. [N.J.A.C. 7:27- 5]	None.	Recordkeeping by manual logging of parameter or storing data in a computer data system upon occurrence of event. Permittee shall record in either a permanent bound log book or in readily accessible computer memories instances (date and time) when the operation of equipment has the potential to cause off-property effects. All records must be maintained on site for a minimum of 5 years. [N.J.A.C. 7:27- 8.13(d)3]	Notify by phone: Upon occurrence of event. Any operation of the equipment which may cause a release of air contaminants in a quantity or concentration which poses a potential threat to public health, welfare, or the environment or which might reasonably result in citizen complaints shall be reported by the Permittee as required by the Air Pollution Control Act. Such notification shall be made by calling the Environmental Action Hotline at (877) 927-6337. [N.J.S.A. 26:2C-19(e)]
11	Compliance with the annual emission limit for each air contaminant (NOx, VOC, CO, SO2, TSP/PM-10) shall be based on hours of operation per year used for testing and maintenance. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
12	The equipment specified in the permit shall be operated only under the following situations: (a) During the performance of normal testing and maintenance procedures, as recommended in writing by the manufacturer and/or as required in writing by a Federal or State law or regulation. (b) When there is a power outage or the facility's primary source of mechanical or thermal energy fails because of an emergency; or (c) When there is a voltage reduction issued by PJM Interconnection, LLC (PJM) and posted on the PJM internet website (www.pjm.com) under the "Emergency Procedures" menu. [N.J.A.C. 7:27-19.1]	Monitored by hour/time monitor continuously. Permittee shall install and operate a totalizing, non-resettable hour meter monitoring the total hours of operation per year for each generator. [N.J.A.C. 7:27- 8.13(d)]	Recordkeeping by manual logging of parameter or storing data in a computer data system upon occurrence of event. The owner or operator of an emergency generator shall record in a logbook or computer data system, the following information for each emergency generator: (a) Total operating time from the emergency generator's hour meter, once per month; (b) If a voltage reduction is the reason for use of the emergency generator, a copy of the voltage reduction notification from PJM or other documentation of the voltage reduction, upon occurrence of event; and (c) If testing or maintenance is the reason for the operation of the emergency generator, the Permittee shall record the following upon occurrence of event: 1.The reason for its operation. 2.The date(s) of operation and the start-up and shutdown time; 3.The total operating time for testing or maintenance based on the emergency generator's hour meter; and 4.The name of the operator. 5.The monthly hours of operation during emergency periods shall be maintained. The owner or operator of an emergency generator shall maintain the records on site for a period of no less than five years after the record was made and shall make the records readily available to the Department or the EPA, upon request. [N.J.A.C. 7:27-19.11]	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
13	Emergency generators shall not be used: 1) In a circumstance other than an emergency; for normal testing and maintenance on days when the Department forecasts air quality anywhere in New Jersey to be "unhealthy for sensitive groups," "unhealthy," or "very unhealthy" or "hazardous" unless required in writing by a Federal or State law or regulation. Procedures for determining the air quality forecasts for New Jersey are available at the Department air quality web site at http://www.state.nj.us/dep/aqpp/aqforecast ; and 2) as a source of energy or power after the primary energy or power source has become operable again. If the primary energy or power source is under the control of the owner or operator of the emergency generator, the owner or operator shall make a reasonable, timely effort to repair the primary energy or power source. [N.J.A.C. 7:27-19.2(d)]	Other: The Permittee shall check the air quality forecast for New Jersey available at the Department air quality website at http://www.state.nj.us/dep/aqpp/aqforecast prior to operating during testing and maintenance periods. [N.J.A.C. 7:27-8.13(d)].	None.	Submit a report: Upon occurrence of event. The permittee shall report any non-compliance in writing within 3 working days after the event to the Regional Enforcement Office. [N.J.A.C. 7:27-8.13(d)4]
14	The emergency generators manufactured after April 1, 2006 (if a fire pump - after July 1, 2006) or modified or reconstructed after July 11, 2005 shall use, beginning October 1, 2010, liquid fuel that contains the following per gallon standards: 15 ppm (0.0015%) maximum sulfur content and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent. [40 CFR 60.4207(b)]	Monitored by review of fuel delivery records once per bulk fuel shipment. For each fuel oil delivery received, the Permitee shall review written documentation of the delivery to ensure the maximum allowable fuel oil sulfur content is not being exceeded. Such written documentation can include, but is not limited to: a bill of lading, delivery invoice, certificate of analysis. [N.J.A.C. 7:27- 8.13(d)]	Recordkeeping by invoices / bills of lading / certificate of analysis once per bulk fuel shipment. The permittee shall keep records of fuel oil sulfur content for each delivery received. All records must be maintained for a minimum of 5 years. [N.J.A.C. 7:27-8.13(d)3]	None.

New Jersey Department of Environmental Protection
Facility Specific Requirements

Ref.#	Applicable Requirement	Monitoring Requirement	Recordkeeping Requirement	Submittal/Action Requirement
15	The owner or operator of an Emergency Generator(s) combusting liquid fuel in a 2007 model year and later engine (in case of a fire pump - during or after a model year that applies to the fire pump engine power rating in Table 3 of NSPS IIII) must use an engine certified to the emission standards in 60.4204(b) or 60.4205(b) or (c), as applicable, for the same model year and maximum engine power (or in case of a fire pump, the NFPA nameplate power). The engine must be installed and configured according to the manufacturer's recommendations. [40 CFR 60.4211(c)]	None.	Other: Keep documentation from the manufacturer that the engine is certified to meet the emission standards. [40 CFR 60.4214(a)2iii] and [N.J.A.C. 7:27-8.13(d)3].	None.
16	The fire pump shall not be tested at the same time as the emergency generator. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
17	The duration of a testing event is restricted to 30 minutes. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.
18	The fire pump shall not be tested during the startup or shutdown of the turbines or the boiler. [N.J.A.C. 7:27-22.16(a)]	None.	None.	None.

Appendix B

Supporting Calculations

Combined Cycle
Combustion Turbine Emissions

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
LOAD																														
Gas Turbine		Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
Plant Load	%	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	87.7	102.7
Duct Burning?		no	no	no	no	no	no	no	no	no	no	no	no	no	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
SITE CONDITIONS																														
Ambient Temp.	°F	-8	10	29.3	50	59	70	80	93	105	70	80	93	105	50	59	70	73	93	105	70	93	105	47.6	50	59	70	93	105	70
GT Evaporative Cooler state		off	off	off	off	off	off	off	off	off	ON		ON	ON	ON	off	off	off	off	off	off	ON	ON	ON	off	off	off	off	off	off
GT FUEL																														
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
LHV	Btu/lb	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00
HHV/LHV		1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105
Fuel Bound Nitrogen	Wt %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Sulfur Content	PPMW	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03
GAS TURBINE DATA (PER UNIT)																														
Fuel Consumption (LHV)	10^6 Btu/hr	2,089.00	2,088.00	2,018.00	1,915.00	1,873.00	1,873.00	1,818.00	1,780.00	1,723.00	1,881.00	1,888.00	1,872.00	1,822.00	1,915.00	1,873.00	1,873.00	1,856.00	1,780.00	1,723.00	1,881.00	1,872.00	1,822.00	1,927.00	1,915.00	1,873.00	1,873.00	1,780.00	1,723.00	1,881.00
Fuel Consumption (HHV)	10^6 Btu/hr	2,319.83	2,318.72	2,240.99	2,126.61	2,079.97	2,079.97	2,018.89	1,976.69	1,913.39	2,088.85	2,096.62	2,078.86	2,023.33	2,126.61	2,079.97	2,079.97	2,061.09	1,976.69	1,913.39	2,088.85	2,078.86	2,023.33	2,139.93	2,126.61	2,079.97	2,079.97	1,976.69	1,913.39	2,088.85
DILUENT INJECTION																														
Type		None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
Flow	10^3 lb/hr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EXHAUST GAS																														
Flow	10^3 lb/hr	4,481.80	4,460.50	4,328.70	4,153.20	4,079.70	4,137.70	4,032.80	3,901.80	3,777.20	4,087.10	4,140.50	4,039.20	3,925.90	4,153.20	4,079.70	4,137.70	4,105.90	3,901.80	3,777.20	4,087.10	4,039.20	3,925.90	4,173.20	4,153.20	4,079.70	4,137.70	3,901.80	3,777.20	4,087.10
Temp.	°F	1,072.10	1,090.40	1,102.80	1,112.60	1,117.70	1,116.90	1,124.20	1,149.60	1,162.10	1,119.00	1,118.40	1,140.70	1,150.80	1,112.60	1,117.70	1,116.90	1,119.00	1,149.60	1,162.10	1,119.00	1,140.70	1,150.80	1,111.30	1,112.60	1,117.70	1,116.90	1,149.60	1,162.10	1,119.00
GT EXHAUST COMPOSITION (VOL %)																														
N2		75.07	75	74.87	74.6	74.4	74.18	73.9	73.43	72.67	73.89	73.56	72.97	72.16	74.6	74.4	74.18	74.1	73.43	72.67	73.89	72.97	72.16	74.64	74.6	74.4	74.18	73.43	72.67	73.89
Ar		0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.87	0.87	0.88	0.88	0.87	0.86	0.89	0.89	0.88	0.88	0.87	0.87	0.88	0.87	0.86	0.89	0.89	0.89	0.88	0.87	0.87	0.88
O2		12.46	12.42	12.41	12.44	12.42	12.48	12.44	12.24	12.07	12.29	12.28	12.02	11.82	12.44	12.42	12.48	12.47	12.24	12.07	12.29	12.02	11.82	12.44	12.44	12.42	12.48	12.24	12.07	12.29
CO2		3.95	3.96	3.95	3.9	3.88	3.82	3.8	3.84	3.82	3.88	3.84	3.89	3.88	3.9	3.88	3.82	3.81	3.84	3.82	3.88	3.89	3.88	3.9	3.9	3.88	3.82	3.84	3.82	3.88
H2O		7.63	7.73	7.88	8.18	8.41	8.64	8.97	9.62	10.58	9.07	9.45	10.25	11.28	8.18	8.41	8.64	8.73	9.62	10.58	9.07	10.25	11.28	8.13	8.18	8.41	8.64	9.62	10.58	9.07
GT EMISSIONS																														
NOx	PPMVD at 15% O2	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
lb/h as NO2		75.6	75.5	73	69.3	67.8	67.7	65.8	64.4	62.3	68	68.3	67.7	65.9	69.3	67.8	67.7	67.1	64.4	62.3	68	67.7	65.9	69.7	69.3	67.8	67.7	64.4	62.3	68
CO	PPMVD	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
lb/h		36.6	36.4	35.3	33.8	33.2	33.6	32.7	31.4	30.2	33.1	33.4	32.4	31.3	33.8	33.2	33.6	33.3	31.4	30.2	33.1	32.4	31.3	34	33.8	33.2	33.6	31.4	30.2	33.1
VOC	PPMVW	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
lb/h as CH4		3.5	3.5	3.4	3.3	3.2	3.3	3.2	3.1	3	3.2	3.3	3.2	3.1	3.3	3.2	3.3	3.3	3.1	3	3.2	3.2	3.1	3.3	3.3	3.2	3.3	3.1	3	3.2
Total Particulates (excluding sulfates), lb/h		9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
SOx	PPMVD at 15% O2	0.1217	0.1221	0.1216	0.1201	0.1194	0.1176	0.117	0.1181	0.1176	0.1194	0.1181	0.1197	0.1194	0.1201	0.1194	0.1176	0.1174	0.1181	0.1176	0.1194	0.1197	0.1194	0.1202	0.1201	0.1194	0.1176	0.1181	0.1176	0.1194
lb/h as SO2		1.164	1.163	1.124	1.067	1.043	1.043	1.013	0.9917	0.9598	1.047	1.052	1.042	1.015	1.067	1.043	1.043	1.034	0.9917	0.9598	1.047	1.042	1.015	1.073	1.067	1.043	1.043	0.9917	0.9598	1.047
lb/h as SO3		0.0766	0.0765	0.074	0.0702	0.0686	0.0686	0.0666	0.0652	0.0631	0.0689	0.0692	0.0686	0.0668	0.0702	0.0686	0.0686	0.068	0.0652	0.0631	0.0689	0.0686	0.0668	0.0706	0.0702	0.0686	0.0686	0.0652	0.0631	0.0689
HRSG DATA (PER UNIT)																														
SUPPLEMENTARY FIRED OPERATION																														
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Burner Fuel	Btu/lb- LHV	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70
Burner heat consumption	10^6 Btu/hr	0	0	0	0	0	0	0	0	0	0	0	0	0	119	168	171	190	199	211	160	177	189	105	105	105	105	105	105	105
SCR Operation		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
CO Catalyst		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
STACK GAS																														
Stack gas flow	10^3 lb/hr	4,481.80	4,460.50	4,328.70	4,153.20	4,079.70	4,137.70	4,032.80	3,901.80	3,777.20	4,087.10	4,140.50	4,039.20	3,925.90	4,159.00	4,087.80	4,146.00	4,115.10	3,911.40	3,787.50	4,094.80	4,047.80	3,935.10	4,178.40	4,158.30	4,084.80	4,142.80	3,906.90	3,782.30	4,092.20
Stack gas flow	10^3 ft^3/hr, Actual	73,965.00	73,498.00	71,176.00	68,342.00	67,263.00	68,601.00	66,980.00	64,890.00	63,158.00	67,784.00	69,072.00	67,568.00	66,076.00	67,957.00	66,770.00	68,026.00	67,496.00	64,323.00	62,551.00	67,259.00	66,999.00	65,460.00	68,290.00	67,989.00	66,906.00	68,203.00	64,528.00	62,789.00	67,400.00
Temp.	°F	183.9	182.7	180.9	180.6	181.2	184.1	184.4	183.7	184.8	183.4	186.1	186	187.3	175.5	174.4	176.6	176	175.4	175.7	176.4	178.3	178.8	175.8	176	176.5	179.1	178.7	179.5	178.4
HRSG EXIT EXHAUST GAS COMPOSITION (VOL %																														
N2		75.07	75	74.87	74.6	74.4	74.18	73.9	73.43	72.67	73.89	73.56	72.97	72.16	74.42	74.15	73.93	73.82	73.12	72.34	73.65	72.71	71.88	74.49	74.44	74.24	74.03	73.27	72.5	73.73
Ar		0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.87	0.87	0.88	0.88	0.87	0.86	0.89	0.88	0.88	0.88	0.87	0.86	0.88	0.87	0.86	0.89	0.89	0.88	0.88	0.87	0.86	0.88
O2		12.46	12.42	12.41	12.44	12.42	12.48	12.44	12.24	12.07	12.29	12.28	12.02	11.82	11.94	11.71	11.76	11.67	11.36	11.11	11.61	11.27	11	12	11.99	11.97	12.03	11.78	11.59	11.84
CO2		3.95	3.96	3.95	3.9	3.88	3.82	3.8	3.84	3.82	3.88	3.84	3.89	3.88	4.13	4.21	4.15	4.19	4.24	4.26	4.19	4.24	4.26	4.11	4.1	4.09	4.02	4.05	4.04	4.08
H2O		7.63	7.73	7.88	8.18	8.41	8.64	8.97	9.62	10.58	9.07	9.45	10.25	11.28	8.62	9.05	9.28	9.45	10.4	11.42	9.67	10.92	12.01	8.52	8.57	8.81	9.03	10.03	11	9.46
EMISSIONS																														
NOx (conc)	PPMVD at 15% O2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
NOx (as NO2) emissions	lb/hr	16.8	16.8	16.2	15.4	15.1	15.1	14.6	14.3	13.8	15.1	15.2	15	14.6	16.4	16.4	16.4	16.5	15.9	15.6	16.4	16.5	16.2	16.3	16.2	15.9	15.9	15.2	14.7	16
CO (act conc)	PPMVD	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.7	2.8	2.8	2.6	2.6	2.6	2.6	2.6	2.7	2.7
CO (ref conc)	ppmvd at 15% O2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
CO emissions	lb/hr	10.2	10.2	9.9	9.4	9.2	9.2	8.9	8.7	8.4	9.2	9.2	9.2	8.9	10	10	10	10	9.7	9.5	10	10	9.9	9.9	9.9	9.7	9.7	9.2	9	9.7
VOC (act conc)	PPMVW	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	2.4	2.5	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4
VOC (ref conc)	ppmvd, ref 15% O2	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
VOC as CH4 emissions	lb/hr	2.9	2.9	2.8	2.7	2.6	2.6	2.5	2.5	2.4	2.6	2.6	2.6	2.6	5.7	5.7	5.7	5.7	5.6	5.4	5.7	5.7	5.6	5.7	5.7	5.5	5.5	5.3	5.1	5.6
Total Particulates (excluding sulfates), lb/h	lb/hr	9	9	9	9	9	9	9	9	9	9	9	9	9	10.3	10.9	10.9	11.1	11.2	11.3	10.8	11	11.1	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Total Particulates (including sulfates), lb/h	lb/hr	10	10	10	9.9	9.9	9.9	9.9	9.9	9.8	9.9	9.9	9.9	9.9	11.3	11.9	11.9	12.1	12.2	12.3	11.8	12	12.1	11.2	11.2	11.1	11.1	11.1	11.1	11.1
SOx (conc)	PPMVD at 15% O2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
SOx (as SO2) emissions	lb/hr	0.77	0.77	0.75	0.71	0.69	0.69	0.67	0.66	0.64	0.7	0.7	0.69	0.67	0.75	0.76	0.76	0.76	0.73	0.72	0.76	0.76	0.74	0.75	0.75	0.73	0.73	0.7	0.68	0.74
SOx (as SO3) emissions	lb/hr	0.56	0.56	0.54	0.52	0.51	0.51	0.49	0.48	0.47	0.51	0.51	0.51	0.49	0.55	0.55	0.55	0.55	0.53	0.52	0.55	0.55	0.54	0.55	0.55	0.53	0.53	0.51	0.49	0.54
NH3 (conc)	PPMVD at 15% O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NH3 emissions	lb/hr	16	16	15	15	14	14	14	14	13	14	15	14	14	15	14	14	14	14	13	14	14	14	15	15	14	14	14	13	14
H2SO4 (assume 35% conv SO2 --> SO3)	lb/hr	0.41	0.41	0.40	0.38	0.37	0.37	0.36	0.35	0.34	0.38	0.38	0.37	0.36	0.40	0.41	0.41	0.41	0.39	0.39	0.41	0.41	0.40	0.40	0.40	0.39	0.39	0.38	0.36	0.40
CO2 emissions - total	lb/hr	255181.80	255059.64	246508.79	233926.83	228796.32	228796.32	222077.79	217435.90	210473.07	229773.56	230628.64	228674.16	222566.41	248206.83	248956.32	249316.32	249519.68	241315.90	235793.07	248973.56	249914.16	245246.41	247992.69	246526.83	241396.32	241396.32	230035.90	223073.07	242373.56
CO2eq emissions - total	lb/hr	257674.69	257551.34	248916.96	236212.08	231031.45	231031.45	224247.29	219560.05	212529.20	232018.23	232881.67	230908.10	224740.68	250575.84	251309.70	251671.81	251868.27	243580.13	237997.72	251330.86	252272.69	247553.72	250366.17	248885.99	243705.36	243705.36	232233.96	225203.11	244692.14
CO2 Emission Factor - turbines (AP-42 Table 3.1-2a)	lb/MMBtu	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
CO2 Emission Factor - duct burner (AP-42 Table 1.4-2)	lb/MMSCF	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000	120000
CO2 Emissions - turbine	lb/hr	255182	255060	246509	233927	228796	228796	222078	217436	210473	229774	230629	228674	222566	233927	228796	228796	226720	217436	210473	229774	228674	222566	235393	233927	228796	228796	217436	210473	229774
CO2 Emissions - duct burner	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14280.0	20160.0	20520.0	22800.0	23880.0	25320.0	19200.0	21240.0	22680.0	12600.0	12600.0	12600.0	12600.0	12600.0	12600.0	12600.0
CH4 Emission Factor - turbines (AP-42 Table 3.1-2a)	lb/MMBtu	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03
CH4 Emission Factor - duct burner (AP-42 Table 1.4-2)	lb/MMSCF	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
CH4 Emissions - turbine	lb/hr	20.0	19.9	19.3	18.3	17.9	17.9	17.4	17.0	16.5	18.0	18.0	17.9	17.4	18.3	17.9	17.9	17.7	17.0	16.5	18.0	17.9	17.4	18.4	18.3	17.9	17.9	17.0	16.5	18.0
CH4 Emissions - duct burner	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.5	0.5	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2
N2O Emission Factor - turbines (AP-42 Table 3.1-2a)	lb/MMBtu	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03
N2O Emission Factor - duct burner (AP-42 Table 1.4-2	lb/MMSCF	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
N2O Emissions - turbine	lb/hr	7.0	7.0	6.7	6.4	6.2	6.2	6.1	5.9	5.7	6.3	6.3	6.2	6.1	6.4	6.2	6.2	6.2	5.9	5.7	6.3	6.2	6.1	6.4	6.4	6.2	6.2	5.9	5.7	6.3
N2O Emissions - duct burner	lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2
CH4 GWP	-	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
N2O GWP	-	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298
CO2 emissions	lb/hr	255182	255060	246509	233927	228796	228796	222078	217436	210473	229774	230629	228674	222566	248207	248956	249316	249520	241316	235793	248974	249914	245246	247993	246527	241396	241396	230036	223073	242374
CH4 emissions	lb/hr	20.0	19.9	19.3	18.3	17.9	17.9	17.4	17.0	16.5	18.0	18.0	17.9	17.4	18.6	18.3	18.3	18.2	17.5	16.9	18.3	18.3	17.8	18.6	18.5	18.1	18.1	17.2	16.7	18.2
N2O emissions	lb/hr	7.0	7.0	6.7	6.4	6.2	6.2	6.1	5.9	5.7	6.3	6.3	6.2	6.1	6.6	6.6	6.6	6.6	6.4	6.2	6.6	6.6	6.5	6.7	6.6	6.5	6.5	6.2	6.0	6.5
CO2 Equivalents - total	lb/hr	257674.7	257551.3	248917.0	236212.1	231031.4	231031.4	224247.3	219560.1	212529.2	232018.2	232881.7	230908.1	224740.7	250575.8	251309.7	251671.8	251868.3	243580.1	237997.7	251330.9	252272.7	247553.7	250366.2	248886.0	243705.4	243705.4	232234.0	225203.1	244692.1
EMISSION RATES AT 100 PERCENT LOAD																														
lb/MMBtu emission rates at 100 Percent Load (LHV)																														
NOx	lb/MMbtu	0.00804	0.00805	0.00803	0.00804	0.00806	0.00806	0.00803	0.00803	0.00801	0.00803	0.00805	0.00801	0.00801	0.00806	0.00804	0.00802	0.00806	0.00803	0.00807	0.00804	0.00805	0.00806	0.00802	0.00802	0.00804	0.00804	0.00806	0.00804	0.00806
VOC	lb/MMbtu	0.00139	0.00139	0.00139	0.00141	0.00139	0.00139	0.00138	0.00140	0.00139	0.00138	0.00138	0.00139	0.00143	0.00280	0.00279	0.00279	0.00279	0.00283	0.00279	0.00279	0.00278	0.00278	0.00281	0.00282	0.00278	0.00278	0.00281	0.00279	0.00282
CO	lb/MMbtu	0.00488	0.00489	0.00491	0.00491	0.00491	0.00491	0.00490	0.00489	0.00488	0.00489	0.00487	0.00491	0.00488	0.00492	0.00490	0.00489	0.00489	0.00490	0.00491	0.00490	0.00488	0.00492	0.00487	0.00490	0.00490	0.00490	0.00488	0.00492	0.00488
PM10/PM2.5	lb/MMbtu	0.00479	0.00479	0.00496	0.00517	0.00529	0.00529	0.00545	0.00556	0.00569	0.00526	0.00524	0.00529	0.00543	0.00556	0.00583	0.00582	0.00591	0.00616	0.00636	0.00578	0.00586	0.00602	0.00551	0.00554	0.00561	0.00561	0.00589	0.00607	0.00559
SO2	lb/MMbtu	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037	0.00037
H2SO4	lb/MMbtu	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020

OPERATING POINT		30	31	32	33	34	35	36	37	38
LOAD										
Gas Turbine		Base	Base	Part	Part	Part	Part	Part	Part	Part
Plant Load	%	107.5	92.5	82.8	78.8	73.9	79	61.2	54	52.9
Duct Burning?		yes	yes	no	no	no	no	no	no	no
SITE CONDITIONS										
Ambient Temp.	°F	93	105	-8	59	105	-8	59	93	105
GT Evaporative Cooler state		ON	ON	ON	off	off	off	off	off	off
GT FUEL										
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG
LHV	Btu/lb	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00	20,577.00
HHV/LHV		1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105
Fuel Bound Nitrogen	Wt %	0	0	0	0	0	0	0	0	0
Fuel Sulfur Content	PPMW	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03
GAS TURBINE DATA (PER UNIT)										
Fuel Consumption (LHV)	10^6 Btu/hr	1,872.00	1,822.00	1,636.00	1,499.00	1,391.00	1,479.00	1,139.00	1,120.00	1,112.00
Fuel Consumption (HHV)	10^6 Btu/hr	2,078.86	2,023.33	1,816.78	1,664.64	1,544.71	1,642.43	1,264.86	1,243.76	1,234.88
DILUENT INJECTION										
Type		None	None	None	None	None	None	None	None	None
Flow	10^3 lb/hr	0	0	0	0	0	0	0	0	0
EXHAUST GAS										
Flow	10^3 lb/hr	4,039.20	3,925.90	3,615.90	3,231.50	3,066.00	3,288.50	2,694.60	2,734.50	2,740.30
Temp.	°F	1,140.70	1,150.80	1,090.50	1,183.00	1,215.00	1,134.80	1,215.00	1,215.00	1,215.00
GT EXHAUST COMPOSITION (VOL %)										
N2		72.97	72.16	75.13	74.34	72.66	75.13	74.57	73.66	72.92
Ar		0.87	0.86	0.89	0.89	0.86	0.89	0.89	0.88	0.87
O2		12.02	11.82	12.63	12.26	12.04	12.64	12.91	12.92	12.82
CO2		3.89	3.88	3.87	3.96	3.84	3.87	3.65	3.52	3.47
H2O		10.25	11.28	7.48	8.56	10.61	7.47	7.98	9.02	9.92
GT EMISSIONS										
NOx	PPMVD at 15% O2	9	9	9	9	9	9	9	9	9
lb/h as NO2		67.7	65.9	59.8	54.8	50.8	54.3	42.1	41.3	41
CO	PPMVD	9	9	9	9	9	9	9	9	9
lb/h		32.4	31.3	29.6	26.2	24.5	26.9	22	22.2	22.1
VOC	PPMVW	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
lb/h as CH4		3.2	3.1	2.9	2.6	2.4	2.6	2.1	2.2	2.2
Total Particulates (excluding sulfates), lb/h		9	9	9	9	9	9	9	9	9
SOx	PPMVD at 15% O2	0.1197	0.1194	0.1181	0.1206	0.117	0.1174	0.1101	0.1062	0.1048
lb/h as SO2		1.042	1.015	0.9112	0.8349	0.7746	0.8237	0.6345	0.6237	0.6191
lb/h as SO3		0.0686	0.0668	0.0599	0.0549	0.051	0.0542	0.0417	0.041	0.0407
HRSG DATA (PER UNIT)										
SUPPLEMENTARY FIRED OPERATION										
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG
Burner Fuel	Btu/lb- LHV	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70	20,577.70
Burner heat consumption	10^6 Btu/hr	105	105	0	0	0	0	0	0	0
SCR Operation		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
CO Catalyst		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
STACK GAS										
Stack gas flow	10^3 lb/hr	4,044.30	3,931.00	3,615.90	3,231.50	3,066.00	3,288.50	2,694.60	2,734.50	2,740.30
Stack gas flow	10^3 ft^3/hr, Actual	67,183.00	65,682.00	58,824.00	52,146.00	50,350.00	53,003.00	43,002.00	44,248.00	44,726.00
Temp.	°F	180.9	182.1	175	167.4	173.2	169.1	161.3	167.1	170.3
HRSG EXIT EXHAUST GAS COMPOSITION (VOL %										
N2		72.82	72	75.13	74.34	72.66	75.13	74.57	73.66	72.92
Ar		0.87	0.86	0.89	0.89	0.86	0.89	0.89	0.88	0.87
O2		11.57	11.36	12.63	12.26	12.04	12.64	12.91	12.92	12.82
CO2		4.09	4.09	3.87	3.96	3.84	3.87	3.65	3.52	3.47
H2O		10.65	11.69	7.48	8.56	10.61	7.47	7.98	9.02	9.92
EMISSIONS										
NOx (conc)	PPMVD at 15% O2	2	2	2	2	2	2	2	2	2
NOx (as NO2) emissions	lb/hr	15.9	15.5	13.3	12.2	11.3	12.1	9.3	9.2	9.1
CO (act conc)	PPMVD	2.7	2.7	2.5	2.5	2.5	2.5	2.3	2.3	2.3
CO (ref conc)	ppmvd at 15% O2	2	2	2	2	2	2	2	2	2
CO emissions	lb/hr	9.7	9.4	8.1	7.4	6.9	7.3	5.7	5.6	5.5
VOC (act conc)	PPMVW	2.4	2.4	1.1	1.2	1.1	1.1	1.1	1	1
VOC (ref conc)	ppmvd, ref 15% O2	2	2	1	1	1	1	1	1	1
VOC as CH4 emissions	lb/hr	5.5	5.4	2.3	2.1	2	2.1	1.6	1.6	1.6
Total Particulates (excluding sulfates), lb/h	lb/hr	10.2	10.2	9	9	9	9	9	9	9
Total Particulates (including sulfates), lb/h	lb/hr	11.1	11.1	9.8	9.7	9.7	9.7	9.6	9.5	9.5
SOx (conc)	PPMVD at 15% O2	1	1	1	1	1	1	1	1	1
SOx (as SO2) emissions	lb/hr	0.73	0.71	0.61	0.56	0.52	0.55	0.42	0.41	0.41
SOx (as SO3) emissions	lb/hr	0.53	0.52	0.44	0.4	0.38	0.4	0.31	0.3	0.3
NH3 (conc)	PPMVD at 15% O2	5	5	5	5	5	5	5	5	5
NH3 emissions	lb/hr	14	14	13	12	11	12	9	9	9
H2SO4 (assume 35% conv SO2 --> SO3)	lb/hr	0.39	0.38	0.33	0.30	0.28	0.29	0.23	0.22	0.22
CO2 emissions - total	lb/hr	241274.16	235166.41	199845.58	183110.35	169917.61	180667.25	139134.55	136813.60	135836.36
CO2eq emissions - total	lb/hr	243582.01	237414.59	201797.89	184899.17	171577.55	182432.20	140493.76	138150.14	137163.36
CO2 Emission Factor - turbines (AP-42 Table 3.1-2a)	lb/MMBtu	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
CO2 Emission Factor - duct burner (AP-42 Table 1.4-2)	lb/MMSCF	120000	120000	120000	120000	120000	120000	120000	120000	120000
CO2 Emissions - turbine	lb/hr	228674	222566	199846	183110	169918	180667	139135	136814	135836
CO2 Emissions - duct burner	lb/hr	12600.0	12600.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CH4 Emission Factor - turbines (AP-42 Table 3.1-2a)	lb/MMBtu	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03	8.60E-03
CH4 Emission Factor - duct burner (AP-42 Table 1.4-2)	lb/MMSCF	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30	2.30
CH4 Emissions - turbine	lb/hr	17.9	17.4	15.6	14.3	13.3	14.1	10.9	10.7	10.6
CH4 Emissions - duct burner	lb/hr	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N2O Emission Factor - turbines (AP-42 Table 3.1-2a)	lb/MMBtu	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03	3.00E-03
N2O Emission Factor - duct burner (AP-42 Table 1.4-2	lb/MMSCF	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
N2O Emissions - turbine	lb/hr	6.2	6.1	5.5	5.0	4.6	4.9	3.8	3.7	3.7
N2O Emissions - duct burner	lb/hr	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CH4 GWP	-	21	21	21	21	21	21	21	21	21
N2O GWP	-	298	298	298	298	298	298	298	298	298
CO2 emissions	lb/hr	241274	235166	199846	183110	169918	180667	139135	136814	135836
CH4 emissions	lb/hr	18.1	17.6	15.6	14.3	13.3	14.1	10.9	10.7	10.6
N2O emissions	lb/hr	6.5	6.3	5.5	5.0	4.6	4.9	3.8	3.7	3.7
CO2 Equivalents - total	lb/hr	243582.0	237414.6	201797.9	184899.2	171577.5	182432.2	140493.8	138150.1	137163.4
EMISSION RATES AT 100 PERCENT LOAD				Max		Proposed Limit				
lb/MMBtu emission rates at 100 Percent Load (LHV)				CT	CT+DB	CT	CT+DB			
NOx	lb/MMbtu	0.00804	0.00804	**0.00806**	**0.00807**	0.00810	0.00810			
VOC	lb/MMbtu	0.00278	0.00280	**0.00143**	**0.00283**	0.00150	0.00290			
CO	lb/MMbtu	0.00491	0.00488	**0.00491**	**0.00492**	0.00500	0.00500			
PM10/PM2.5	lb/MMbtu	0.00561	0.00576	**0.00569**	**0.00636**	0.00570	0.00640			
SO2	lb/MMbtu	0.00037	0.00037	**0.00037**	**0.00037**	0.00037	0.00037			
H2SO4	lb/MMbtu	0.00020	0.00020	**0.00020**	**0.00020**	0.00020	0.00020			

Summary of Annual Emissions
Newark Energy Center

10/4/2011

Max Annual Emissions - facility wide (including startup and shutdown)

number of CTs	2	NOx	CO	VOC	SO2	PM2.5	NH3	H2SO4	Pb	CO2	CO2e
combustion turbines	tpy	142.1	484.7	35.5	6.2	90.3	122.6	3.3	0	2,040,544	2,060,336
ancillary equipment	tpy	1.5	1.6	0.3	0.0	0.3	0.0000	1.02E-03	1.12E-05	3,138	3,156
cooling tower	tpy	0.0	0.0	0.0	0.0	2.5	0	0	0	0	0
TOTAL	**TPY**	**143.6**	**486.3**	**35.8**	**6.2**	**93.1**	**122.6**	**3.3**	**0.0**	**2043681.4**	**2063492.4**

Max Annual Emissions - per unit (including startup and shutdown)

	steady state emissions[[no DB] / [DB]]	lb/hr	15.1	16.4	9.2	10	2.6	5.7	0.69	0.76	9.9	11.9
Potential Annual Hours			**NOx**		**CO**		**VOC**		**SO2**		**PM10/PM2.5**	
			tons	**hours**	**tpy**	**hours**	**tpy**	**hours**	**tpy**	**hours**	**tpy**	**hours**
6960.0	steady state - no DB		32.1	4257.5	2.3	503.3	5.5	4257.5	2.4	6960.0	34.5	6960.0
1800.0	steady state - with DB		14.8	1800.0	9.0	1800.0	5.1	1800.0	0.7	1800.0	10.7	1800.0
3754.2	cold start		0.0	0.0	62.5	3754.2	0.0	0.0	0.0	0.0	0.0	0.0
0.0	hot start		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2312.5	warm start		20.4	2312.5	86.6	2312.5	5.0	2312.5	0.0	0.0	0.0	0.0
390.0	shutdown		3.8	390.0	81.9	390.0	2.1	390.0	0.0	0.0	0.0	0.0
	TOTAL	**TPY**	**71.0**	**8760.0**	**242.3**	**8760.0**	**17.8**	**8760.0**	**3.1**	**8760.0**	**45.2**	**8760.0**

steady state emissions are assumed for events that are self correcting

SUMMARY OF SU/SD INFORMATION

Self Correcting?

			NOx	CO	VOC	SO2	PM10/PM2.5
	cold start emissions		yes	**no**	yes	yes	yes
	hot start emissions		**no**	**no**	**no**	yes	yes
	warm start emissions		**no**	**no**	**no**	yes	yes
	shutdown emissions		**no**	**no**	**no**	yes	yes

red value indicates not self-correcting

Summary of Avg Hourly Emissions (including downtime for SU/SD events)

hours/event (downtime + duration)			NOx	CO	VOC	SO2	PM10/PM2.5
75.08	cold start emissions	lb/hr	6.27	33.30	1.89	0.00	0.49
4.65	hot start emissions	lb/hr	19.35	118.28	5.59	0.00	1.72
9.25	warm start emissions	lb/hr	17.62	74.92	4.32	0.00	1.62
1.30	shutdown emissions	lb/hr	19.23	420.00	10.77	0.00	3.08

SU/SD Emissions per event

number/year			NOx	CO	VOC	SO2	PM10/PM2.5
50	cold start emissions	lbs	471.00	2500.00	142.00	0.00	37.00
0	hot start emissions	lbs	90.00	550.00	26.00	0.00	8.00
250	warm start emissions	lbs	163.00	693.00	40.00	0.00	15.00
300	shutdown emissions	lbs	25.00	546.00	14.00	0.00	4.00

Summary of Annual Emissions
Newark Energy Center

10/4/2011

Overall Assumptions

number of CTs	2	
duct burning hours	0	hrs/yr
steady state hours per unit	8760	

Steady State Emissions Data

Emissions data dated 8-3-11
Emissions at ISO conditions (100% load 59 F) with and without DB
Emissions Case 5 (no DB) and Case 15 (w/DB)
NOx emissions assume SCR
CO and VOC assume oxidation catalyst
SO2 emissions assume no conversion to SO3 and 0.22 grains/100 SCF
H2SO4 emissions assume 35% conversion to SO3 and no conversion to ammonium sulfate

Each Turbine

		NOx	CO	VOC	SO2	PM10/PM2.5	NH3	H2SO4	CO2	CO2e
Emissions - (Case 5) - No DB	lb/hr	15.1	9.2	2.6	0.69	9.9	14	0.370	228796	231031
Emissions - (Case 15) - w/DB	lb/hr	16.4	10	5.7	0.76	11.9	14	0.407	248956	251310
Emissions from DB	lb/hr	1.3	0.8	3.1	0.07	2	0	0.0375156	20160	20278.2552
operating hours no DB	hrs/yr	6960	6960	6960	6960	6960	6960	6960	6960	6960
operating hours with DB	hrs/yr	1800	1800	1800	1800	1800	1800	1800	1800	1800
steady state emissions per turbine	tpy	67.308	41.016	14.178	3.0852	45.162	61.32	1.65	1020272	1030168

Both Turbines

number of turbines		2	2	2	2	2	2	2	2	2
total plant emissions emissions - steady state	tpy	134.62	82.03	28.36	6.17	90.32	122.64	3.31	2040543.72	2060336.34

Summary of Annual Emissions
Newark Energy Center

10/4/2011

Overall Assumptions

SU/SD information 207FA.05 Combined Cycle Plant Conventional Start (dated 7/7/10) - received March 2011

cold starts/unit	50	number/yr	3.08	hours/event	72	minimum hours downtime with event	185 minutes per event
hot starts/unit	0	number/yr	0.65	hours/event	4	minimum hours downtime with event	39 minutes per event
warm starts/unit	250	number/yr	1.25	hours/event	8	minimum hours downtime with event	75 minutes per event
shutdowns/unit	300	number/yr	0.30	hours/event	1	minimum hours downtime with event	18 minutes per event

		NOx	CO	VOC	SO2	PM10/PM2.5
Emissions per cold start	lbs	471	2500	142		37
Emissions per hot start	lbs	90	550	26		8
Emissions per warm start	lbs	163	693	40		15
Emissions per shutdown	lbs	25	546	14		4
cold start - duration of event (include downtime)	hrs	75.08	75.08	75.08	75.08	75.08
hot start - duration of event (include downtime)	hrs	4.65	4.65	4.65	4.65	4.65
warm start - duration of event (include downtime)	hrs	9.25	9.25	9.25	9.25	9.25
shutdown - duration of event (include downtime)	hrs	1.30	1.30	1.30	1.30	1.30
cold start - avg hourly emissions (including downtime)	lb/hr	6.27	33.30	1.89	0.00	0.493
hot start - avg hourly emissions (including downtime)	lb/hr	19.35	118.28	5.59	0.0	1.720
warm start - avg hourly emissions (including downtime)	lb/hr	17.62	74.92	4.32	0.00	1.62
shutdown - avg hourly emissions (including downtime)	lb/hr	19.23	420.00	10.77	0.00	3.08
steady state average hourly		15.37	9.36	3.24		10.31
cold start - self correcting?	-	yes	no	yes	yes	yes
hot start - self correcting?	-	no	no	no	yes	yes
warm start - self correcting?	-	no	no	no	yes	yes
shutdown - self correcting?	-	no	no	no	yes	yes
cold start - hourly emissions (exlcuding downtime)	lb/hr	152.76	810.81	46.05	0.00	12.00
hot start - hourly emissions (exlcuding downtime)	lb/hr	138.46	846.15	40.00	0.00	12.31
warm start - hourly emissions (exlcuding downtime)	lb/hr	130.40	554.40	32.00	0.00	12.00
shutdown- hourly emissions (exlcuding downtime)	lb/hr	83.33	1820.00	46.67	0.00	13.33
cold start - short term emissions	g/s	19.3	102.3	5.8	0.0	1.5
hot start - short term emissions	g/s	17.5	106.7	5.0	0.0	1.6
warm start - short term emissions	g/s	16.4	69.9	4.0	0.0	1.5
shutdown - short term emissions	g/s	10.5	229.5	5.9	0.0	1.7

Emissions From Ancillary Equipment
Newark Energy Center

Total Emissions form Ancillary Equipment (tpy)

		NOx	CO	VOC	SO2	PM10/ PM2.5	lead (Pb)	H2SO4	CO2	CO2e
Auxilliary Boiler	tpy	0.53	0.98	0.13	0.01	0.26	0.00	1.01E-03	3,115.29	3133.58
Emergency Generator	tpy	0.93	0.58	0.13	0.001	0.03	9.85E-06	1.67E-06	6.79	6.79
Emergency Fire Pump	tpy	0.08	0.08	0.01	0.0001	0.004	1.32E-06	2.93E-06	15.59	15.65
TOTAL	tpy	**1.53**	**1.64**	**0.27**	**0.01**	**0.30**	**1.12E-05**	**1.02E-03**	**3,137.68**	**3,156.02**

Emissions (lb/hr)

		NOx	CO	VOC	SO2	PM10/ PM2.5	lead (Pb)
Auxilliary Boiler		1.324	2.449	0.331	0.033	0.66	0.00E+00
Emergency Generator		18.527	11.564	2.618	0.016	0.66	1.97E-04
Emergency Fire Pump		1.555	1.553	0.220	0.002	0.09	2.65E-05

Emissions for Modeling (g/s) - annual average

		NOx	CO	VOC	SO2	PM10/ PM2.5	lead (Pb)
Auxilliary Boiler		0.015	0.028	0.0038	0.000381	0.007624	0.00E+00
Emergency Generator		0.027	0.017	0.0038	0.000023	0.000951	2.84E-07
Emergency Fire Pump		0.002	0.002	0.0003	0.000003	0.000128	3.81E-08

Emissions for Modeling (g/s) - hourly average

		NOx	CO	VOC	SO2	PM10/ PM2.5	lead (Pb)
Auxilliary Boiler		0.17	0.31	0.04	0.00417	0.08	0.00E+00
Emergency Generator		2.34	1.46	0.33	0.00199	0.08	2.49E-05
Emergency Fire Pump		0.20	0.20	0.03	0.00027	0.01	3.34E-06

Auxilliary Boiler

		NOx	CO	VOC	SO2	PM10/ PM2.5		H2SO4	CO2	CH4	N2O	CO2e
Maximum Input Capacity	MMBtu/hr	66.2	66.2	66.2	66.2	66.2		66.2	66.2	66.2	66.2	
Emission Factor	lb/MMBtu	0.02	0.037	0.005	0.0005	0.010		0.00004	117.65	0.0022772	0.002156863	
Operating Hours per Years	hrs/yr	800	800	800	800	800		800	800	800	800	
Potential Emissions	lb/hr	1.32	2.45	0.33	0.03	0.66		0.003	0.051	0.000	0.004	
Potential Emissions	**tpy**	**0.53**	**0.98**	**0.13**	**0.01**	**0.26**		**0.001**	**3115.294**	**0.060**	**0.057**	**3133.58**

emission factors for NOx, CO, VOC, SO2 and PM10/PM2.5 provided by Siemens (March 2009)
emissions of H2SO4 assumes a 5% conversion of SO2 --> SO3 (on a molar basis)
CO2, CH4 and N2O Emisison Factors from AP-42 Table 1.4-2

Emissions From Ancillary Equipment

Newark Energy Center

Emergency Generator

		NOx	**CO**	**VOC**	**SO2**	**PM10/ PM2.5**	**lead (Pb)**	**H2SO4**	**CO2**	**CH4**	**N2O**	**CO2e**
Power rating	kW	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	
Power rating	hp	2011.1	2011.1	2011.1	2011.1	2011.1	2011.05	153.97102	117.65	0.0022772	0.002156863	
emission factor	g/kW hr	5.61	3.5	0.79	0.0048	0.2						
emission factor	g/bhp hr						4.45E-05	9.85E-05	5.24E+02	2.57E-02	4.20E-03	
emissions	lb/hr	18.527	11.564	2.618	0.016	0.661	0.0002	3.34E-05	135.882	0.000	0.000	
operating hours per year	hrs/yr	100	100	100	100	100	100	100.00	100.00	100.00	100.00	
hourly emissions (30 min/hr)	lb/hr	9.264	5.782	1.309	0.008	0.330	0.0001	0.000	67.941	0.0000001	0.000	
Potential Emissions	**tpy**	**0.93**	**0.58**	**0.13**	**0.0008**	**0.03**	**9.85E-06**	**0.0000017**	**6.7941176**	**0.0000000**	**0.0000000**	**6.794118**

emission factors for NOx, CO, VOC and PM10/PM2.5 based on Tier2 standards - NOx and VOC breakdown based on Tier 1 standards

emission factor for SO2 based on ULSD fuel oil (sulfur content of 15 ppmw or 0.0015 lb/MMBtu) and fuel input ratio of 7000 Btu/hp hr (AP-42 Section 3.3)

emission factor for Pb based on AP-42 Section 3.1 (1.4e-5 lb/MMBtu) and fuel input of 7000 Btu/hp hr (AP-42 Section 3.3)

emission factor for H2SO4 (0.000031 lb/MMBTu) from Toxic air pollutant emission factors - a compilation for selected compounds and sources (EPA, 1990) and fuel input ratio of 7000 Btu/hp

emission factor for CO2 (165 lb/MMBtu) from AP-42 Table 3.4-1

emission factor for CH4 (0.0081 lb/MMBtu) from AP-42 Table 3.4-1

emission factor for N2O from Climate Registry General Reporting Protocol (GRP)

Emergency Fire Pump

		NOx	**CO**	**VOC**	**SO2**	**PM10/ PM2.5**	**lead (Pb)**	**H2SO4**	**CO2**	**CH4**	**N2O**	**CO2e**
Power rating	hp	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	270.0	
Power rating	kW	201.4	201.4	201.4	201.4	201.4	201.4	201.4	201.4	201.4	201.4	
emission factor	g/kW hr	3.50	3.5	0.50	0.0048	0.2						
emission factor	g/bhp hr						4.45E-05	9.85E-05	5.24E+02	2.57E-02	4.20E-03	
emissions	lb/hr	1.555	1.553	0.220	0.002	0.089	2.65E-05	5.86E-05	3.12E+02	1.53E-02	2.50E-03	
operating hours per year	hrs/yr	100	100	100	100	100	100	100	100	100	100	
hourly emissions (30 min/hr)	lb/hr	0.777	0.776	0.110	0.001	0.044	0.00001	0.000	155.925	0.008	0.001	
Potential Emissions	**tpy**	**0.08**	**0.08**	**0.01**	**0.0001**	**0.004**	**1.32E-06**	**2.93E-06**	**1.56E+01**	**7.65E-04**	**1.25E-04**	**15.64579**

emission factors for NOx, CO, VOC and PM10/PM2.5 based on Tier 3 standards - NOx and VOC breakdown based on Tier 1 standards

emission factor for SO2 based on ULSD fuel oil (sulfur content of 15 ppmw or 0.0015 lb/MMBtu) and fuel input ratio of 7000 Btu/hp hr (AP-42 Section 3.3)

emission factor for Pb based on AP-42 Section 3.1 (1.4e-5 lb/MMBtu) and fuel input of 7000 Btu/hp hr (AP-42 Section 3.3)

emission factor for H2SO4 (0.000031 lb/MMBTu) from Toxic air pollutant emission factors - a compilation for selected compounds and sources (EPA, 1990) and fuel input ratio of 7000 Btu/hp

emission factor for CO2 (165 lb/MMBtu) from AP-42 Table 3.4-1

emission factor for CH4 (0.0081 lb/MMBtu) from AP-42 Table 3.4-1

emission factor for N2O from Climate Registry General Reporting Protocol (GRP)

Estimated Emissions from Cooling Tower

Emissions

		PM10	PM2.5
recirculating water flow	gpm	220870	220870
drift eliminator efficiency	%	0.0005%	0.0005%
TDS in recirculating water	mg/l	4150	4150
particle size distribution	%	0.55	0.25
estimated emissions	lb/hr	**1.261**	**0.573**
estimated emissions	tpy	**5.523**	**2.511**
number of cells	-	**12**	**12**
estimated emissions per cell	lb/hr	**0.11**	**0.048**

96.1

Particulate Distribution

dissolved solids (assumes solids have same density as water)

4.15	g/l	solids content
1000	g/l	water density
0.00415		mass ratio

then 0.1609941 ratio of radius after evaporation to radius of droplet
(this is (0.00415)^(1/3), since mass is proportional to R^3)

% of emitted mass larger than			
Percentage		droplet radius (micron)	droplet radius (micron)
80	larger than	15	2.4
75	larger than	20	3.2
70	larger than	25	4.0
65	larger than	30	4.8
60	larger than	35	5.6
40	larger than	65	10.5
20	larger than	115	18.5
10	larger than	170	27.4

these are interpolated
these are interpolated
these are interpolated

Conclude:
less than 25 percent of PM from cooling tower will be PM2.5
less than 55 percent of PM from cooling tower will be PM10

droplet size distribution provided by the vendor

Hess Newark Energy Center

Summary of HAP Emissions

Max Individual HAP	**2.59**
Total HAPs	**8.47**

Summary of HAP Emissions (tpy)

Pollutant	HAPs	Turbines + DB	Aux Boiler	Fire Engine	Emer. Gen	Total HAP
1,3-Butadiene	HAP	0.009	0.00	0.00	0.00	0.009
2-Methylnaphthalene	0	0.00	0.00	0.00	0.00	0.00
Acetaldehyde	HAP	0.80	0.00	0.00	0.00	0.80
Acrolein	HAP	0.06	0.00	0.00	0.00	0.06
Anthracene	HAP	0.00	0.00	0.00	0.00	0.00
Ammonia	0	0.00	0.00	0.00	0.00	0.00
Benzene	HAP	0.24	0.00	0.00	0.00	0.24
Benzo(a)anthracene	HAP	0.00	0.00	0.00	0.00	0.000
Benzo(a)pyrene	HAP	0.00	0.00	0.00	0.00	0.000
Butane	0	0.00	0.00	0.00	0.00	0.00
Chrysene	0	0.00	0.00	0.00	0.00	0.00
Dibenz(a,h)anthracene	0	0.00	0.00	0.00	0.00	0.00
Ethane	0	0.00	0.00	0.00	0.00	0.00
Ethylbenzene	HAP	0.64	0.00	0.00	0.00	0.64
Formaldehyde	HAP	2.21	0.00	0.00	0.00	2.22
Hexane	HAP	0.00	0.00	0.00	0.00	0.00
Naphthalene	HAP	0.03	0.00	0.00	0.00	0.03
Pentane	0	0.00	0.00	0.00	0.00	0.00
Phenanthrene	0	0.00	0.00	0.00	0.00	0.00
PAH	HAP	0.04	0.00	0.00	0.00	0.04
Propane	0	0.00	0.00	0.00	0.00	0.00
Propylene	0	0.00	0.00	0.00	0.00	0.00
Propylene Oxide	HAP	0.58	0.00	0.00	0.00	0.58
Pyrene	0	0.00	0.00	0.00	0.00	0.00
Sulfuric Acid	0	0.00	0.00	0.00	0.00	0.00
Toluene	HAP	2.59	0.00	0.00	0.00	2.59
Xylene (Total)	HAP	1.27	0.00	0.00	0.00	1.27
Arsenic	HAP	0.00	0.00	0.00	0.00	0.0001
Barium	0	0.00	0.00	0.00	0.00	0.00
Beryllium	HAP	0.00	0.00	0.00	0.00	0.0000
Cadmium	HAP	0.00	0.00	0.00	0.00	0.000
Chromium	HAP	0.00	0.00	0.00	0.00	0.00
Cobalt	HAP	0.00	0.00	0.00	0.00	0.00
Copper	0	0.00	0.00	0.00	0.00	0.00
Manganese	HAP	0.00	0.00	0.00	0.00	0.00
Mercury	HAP	0.00	0.00	0.00	0.00	0.000
Molybdenum	0	0.00	0.00	0.00	0.00	0.00
Nickel	HAP	0.00	0.00	0.00	0.00	0.00
Selenium	HAP	0.00	0.00	0.00	0.00	0.00
Vanadium	0	0.00	0.00	0.00	0.00	0.00
Zinc	0	0.00	0.00	0.00	0.00	0.00

Hess Newark Energy Center
Summary of Air Toxic Emissions

Summary of Air Toxic Emissions (lb/yr)

						(lb/yr)		(lb/yr)	
Pollutant	**HAPs**	**One Turbine + DB**	**Aux Boiler**	**Fire Engine**	**Emer. Gen**	**Reporting Threshold**	**Report?**	**SOTA Threshold**	**SOTA?**
1,3-Butadiene	HAP	8.560	0.00	0.01	0.06	14.000	no	140	no
2-Methylnaphthalene	0	0.007	0.00	0.00	0.00	na	no	na	no
Acetaldehyde	HAP	796.238	0.00	0.16	1.10	1800.00	no	10000	no
Acrolein	HAP	58.203	0.00	0.02	0.13	8.000	**yes**	80	no
Anthracene	HAP	0.001	0.00	0.00	0.00	na	no	na	no
Ammonia	0	16.000	0.00	0.00	0.00	0.05	**yes**	5	**yes**
Benzene	HAP	0.028	0.12	0.19	1.34	0.01	**yes**	4000	no
Benzo(a)anthracene	HAP	0.001	0.00	0.00	0.00	2.000	no	20	no
Benzo(a)pyrene	HAP	0.000	0.00	0.00	0.00	2.000	no	20	no
Butane	0	626.087	115.14	0.00	0.00	na	no	na	no
Chrysene	0	0.001	0.00	0.00	0.00	na	no	na	no
Dibenz(a,h)anthracene	0	0.000	0.00	0.00	0.00	na	no	na	no
Ethane	0	924.224	169.97	0.00	0.00	na	no	na	no
Ethylbenzene	HAP	636.990	0.00	0.00	0.00	2000.00	no	10000	no
Formaldehyde	HAP	2212.014	4.11	0.24	1.69	400.00	**yes**	4000	no
Hexane	HAP	1.371	0.25	0.00	0.00	2000.00	no	10000	no
Naphthalene	HAP	26.060	0.03	0.02	0.12	2000.00	no	10000	no
Pentane	0	775.155	142.55	0.00	0.00	na	no	na	no
Phenanthrene	0	0.005	0.00	0.01	0.04	na	no	na	no
PAH	HAP	43.821	0.01	0.03	0.24	na	no	na	no
Propane	0	477.019	87.72	0.00	0.00	na	no	na	no
Propylene	0	0.000	0.00	0.05	0.37	na	no	na	no
Propylene Oxide	HAP	577.272	0.00	0.00	0.00	1000.00	no	10000	no
Pyrene	0	0.001	0.00	0.00	0.01	na	no	na	no
Sulfuric Acid	0	3591.600	0.00	0.01	0.00	na	no	na	no
Toluene	HAP	2588.787	0.19	0.08	0.59	2000.00	**yes**	10000	no
Xylene (Total)	HAP	1273.981	0.00	0.06	0.41	2000.00	no	10000	no
Arsenic	HAP	0.060	0.01	0.00	0.00	1.0000	no	10	no
Barium	0	1.312	0.24	0.00	0.00	na	no	na	no
Beryllium	HAP	0.004	0.00	0.00	0.00	1.6000	no	16	no
Cadmium	HAP	0.328	0.06	0.00	0.00	2.000	no	20	no
Chromium	HAP	0.417	0.08	0.00	0.00	1000.00	no	10000	no
Cobalt	HAP	0.025	0.00	0.00	0.00	20.00	no	200	no
Copper	0	0.253	0.05	0.00	0.00	na	no	na	no
Manganese	HAP	0.113	0.02	0.00	0.00	160.00	no	1600	no
Mercury	HAP	0.078	0.01	0.00	0.00	2.000	no	20	no
Molybdenum	0	0.328	0.06	0.00	0.00	na	no	na	no
Nickel	HAP	0.626	0.12	0.00	0.00	200.00	no	2000	no
Selenium	HAP	0.007	0.00	0.00	0.00	20.00	no	200	no
Vanadium	0	0.686	0.13	0.00	0.00	na	no	na	no
Zinc	0	8.646	1.59	0.00	0.00	na	no	na	no

Hess Newark Energy Center

Air Toxic Emissions

Natural Gas Fired Combustion Turbines

	Units		Case 20	Case1
Ambient Temperature	^{o}F		93	-8
CTG Percent Load Rate	%		100%	100%
CTG Heat Input Capacity	MMBtu/hr, LHV		1,872	2,089
CTG Heat Input Capacity	MMBtu/hr, HHV		2,089	2,320
Duct Burner Input			160	0
HHV of natural gas	BTU/SCF		966	966
number of turbines			2	2
annual hours of operation			1,800	6,960

Worst Case Turbines and Duct Burner

	lb/MMBTU	lb/MMBTU	lb/hr per turbine	lb/hr per turbine	Max - All Turbines			
Air Toxic	**Turbine Emission Factor**	**DB Emission Factor**	**Case 20**	**Case1**	**Max lb/hr**	**tons/yr**	**HAP**	**HAP tons/yr**
1,3-Butadiene	4.30E-07	0.00E+00	0.00	0.00	0.00	0.01	HAP	0.01
2-Methylnaphthalene	0.00E+00	2.48E-08	0.00	0.00	0.00	0.00	0.00	0.00
Acetaldehyde	4.00E-05	0.00E+00	0.08	0.09	0.19	0.80	HAP	0.80
Acrolein	Assuming 50% control on catalyst		0.01	0.01	0.01	0.06	HAP	0.06
Anthracene	0.00E+00	2.48E-09	0.00	0.00	0.00	0.00	HAP	0.00
Ammonia	emissions from vendor data		14.00	16.00	32.00	136.56	0.00	0.00
Benzene	1.20E-05	2.17E-06	0.03	0.03	0.06	0.24	HAP	0.24
Benzo(a)anthracene	0.00E+00	1.86E-09	0.00	0.00	0.00	0.00	HAP	0.00
Benzo(a)pyrene	0.00E+00	1.24E-09	0.00	0.00	0.00	0.00	HAP	0.00
Butane	0.00E+00	2.17E-03	0.35	0.00	0.70	0.63	0.00	0.00
Chrysene	0.00E+00	1.86E-09	0.00	0.00	0.00	0.00	0.00	0.00
Dibenz(a,h)anthracene	0.00E+00	1.24E-09	0.00	0.00	0.00	0.00	0.00	0.00
Ethane	0.00E+00	3.21E-03	0.51	0.00	1.03	0.92	0.00	0.00
Ethylbenzene	3.20E-05	0.00E+00	0.07	0.07	0.15	0.64	HAP	0.64
Formaldehyde	1.10E-04	7.76E-05	0.24	0.26	0.51	2.21	HAP	2.21
Hexane	0.00E+00	4.76E-06	0.00	0.00	0.00	0.00	HAP	0.00
Naphthalene	1.30E-06	6.31E-07	0.00	0.00	0.01	0.03	HAP	0.03
Pentane	0.00E+00	2.69E-03	0.43	0.00	0.86	0.78	0.00	0.00
Phenanthrene	0.00E+00	1.76E-08	0.00	0.00	0.00	0.00	0.00	0.00
PAH	2.20E-06	9.76E-08	0.00	0.01	0.01	0.04	HAP	0.04
Propane	0.00E+00	1.66E-03	0.27	0.00	0.53	0.48	0.00	0.00
Propylene	0.00E+00	0.00E+00	0.00	0.00	0.00	0.00	0.00	0.00
Propylene Oxide	2.90E-05	0.00E+00	0.06	0.07	0.13	0.58	HAP	0.58
Pyrene	0.00E+00	5.18E-09	0.00	0.00	0.00	0.00	0.00	0.00
Sulfuric Acid	emissions from vendor data		0.41	0.41	0.82	3.59	0.00	0.00
Toluene	1.30E-04	3.52E-06	0.27	0.30	0.60	2.59	HAP	2.59
Xylene (Total)	6.40E-05	0.00E+00	0.13	0.15	0.30	1.27	HAP	1.27
Arsenic	0.00E+00	2.07E-07	0.00	0.00	0.00	0.00	HAP	0.00
Barium	0.00E+00	4.55E-06	0.00	0.00	0.00	0.00	0.00	0.00
Beryllium	0.00E+00	1.24E-08	0.00	0.00	0.00	0.00	HAP	0.00
Cadmium	0.00E+00	1.14E-06	0.00	0.00	0.00	0.00	HAP	0.00
Chromium	0.00E+00	1.45E-06	0.00	0.00	0.00	0.00	HAP	0.00
Cobalt	0.00E+00	8.70E-08	0.00	0.00	0.00	0.00	HAP	0.00
Copper	0.00E+00	8.80E-07	0.00	0.00	0.00	0.00	0.00	0.00
Manganese	0.00E+00	3.93E-07	0.00	0.00	0.00	0.00	HAP	0.00
Mercury	0.00E+00	2.69E-07	0.00	0.00	0.00	0.00	HAP	0.00
Molybdenum	0.00E+00	1.14E-06	0.00	0.00	0.00	0.00	0.00	0.00
Nickel	0.00E+00	2.17E-06	0.00	0.00	0.00	0.00	HAP	0.00
Selenium	0.00E+00	2.48E-08	0.00	0.00	0.00	0.00	HAP	0.00
Vanadium	0.00E+00	2.38E-06	0.00	0.00	0.00	0.00	0.00	0.00
Zinc	0.00E+00	3.00E-05	0.00	0.00	0.01	0.01	0.00	0.00

Hess Newark Energy Center

Air Toxic Emissions

Natural Gas Fired Auxilliary Boiler

	Units		Value
Boiler Heat Input	MMBtu/hr, HHV		66
number of boilers			1
annual hours of operation			800
HHV of natural gas	BTU/SCF		966

Emissions Auxilliary Boiler

	Emission Factor	Emission Factor				
Air Toxic	**lb/MMSCF**	**lb/MMBtu**	**lb/hr**	**ton/yr**	**HAPs**	**HAP ton/yr**
1,3-Butadiene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
2-Methylnaphthalene	2.40E-05	2.48E-08	1.64E-06	6.58E-07	0	0.00E+00
Acetaldehyde	0.00E+00	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Acrolein	0.00E+00	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Anthracene	2.40E-06	2.48E-09	1.64E-07	6.58E-08	HAP	6.58E-08
Ammonia	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Benzene	2.10E-03	2.17E-06	1.44E-04	5.76E-05	HAP	5.76E-05
Benzo(a)anthracene	1.80E-06	1.86E-09	1.23E-07	4.93E-08	HAP	4.93E-08
Benzo(a)pyrene	1.20E-06	1.24E-09	8.22E-08	3.29E-08	HAP	3.29E-08
Butane	2.10E+00	2.17E-03	1.44E-01	5.76E-02	0	0.00E+00
Chrysene	1.80E-06	1.86E-09	1.23E-07	4.93E-08	0	0.00E+00
Dibenz(a,h)anthracene	1.20E-06	1.24E-09	8.22E-08	3.29E-08	0	0.00E+00
Ethane	3.10E+00	3.21E-03	2.12E-01	8.50E-02	0	0.00E+00
Ethylbenzene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Formaldehyde	7.50E-02	7.76E-05	5.14E-03	2.06E-03	HAP	2.06E-03
Hexane	4.60E-03	4.76E-06	3.15E-04	1.26E-04	HAP	1.26E-04
Naphthalene	6.10E-04	6.32E-07	4.18E-05	1.67E-05	HAP	1.67E-05
Pentane	2.60E+00	2.69E-03	1.78E-01	7.13E-02	0	0.00E+00
Phenanthrene	1.70E-05	1.76E-08	1.17E-06	4.66E-07	0	0.00E+00
PAH	9.43E-05	9.76E-08	6.46E-06	2.59E-06	HAP	2.59E-06
Propane	1.60E+00	1.66E-03	1.10E-01	4.39E-02	0	0.00E+00
Propylene	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Propylene Oxide	0.00E+00	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Pyrene	5.00E-06	5.18E-09	3.43E-07	1.37E-07	0	0.00E+00
Sulfuric Acid	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Toluene	3.40E-03	3.52E-06	2.33E-04	9.32E-05	HAP	9.32E-05
Xylene (Total)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Arsenic	2.00E-04	2.07E-07	1.37E-05	5.48E-06	HAP	5.48E-06
Barium	4.40E-03	4.56E-06	3.02E-04	1.21E-04	0	0.00E+00
Beryllium	1.20E-05	1.24E-08	8.22E-07	3.29E-07	HAP	3.29E-07
Cadmium	1.10E-03	1.14E-06	7.54E-05	3.02E-05	HAP	3.02E-05
Chromium	1.40E-03	1.45E-06	9.59E-05	3.84E-05	HAP	3.84E-05
Cobalt	8.40E-05	8.70E-08	5.76E-06	2.30E-06	HAP	2.30E-06
Copper	8.50E-04	8.80E-07	5.83E-05	2.33E-05	0	0.00E+00
Manganese	3.80E-04	3.93E-07	2.60E-05	1.04E-05	HAP	1.04E-05
Mercury	2.60E-04	2.69E-07	1.78E-05	7.13E-06	HAP	7.13E-06
Molybdenum	1.10E-03	1.14E-06	7.54E-05	3.02E-05	0	0.00E+00
Nickel	2.10E-03	2.17E-06	1.44E-04	5.76E-05	HAP	5.76E-05
Selenium	2.40E-05	2.48E-08	1.64E-06	6.58E-07	HAP	6.58E-07
Vanadium	2.30E-03	2.38E-06	1.58E-04	6.31E-05	0	0.00E+00
Zinc	2.90E-02	3.00E-05	1.99E-03	7.95E-04	0	0.00E+00

Hess Newark Energy Center

Air Toxic Emissions

Emergency Fire Pump and Emergency Generator

	Units	Fire Pump
Maximum Fuel Flow	gal/hr	15
Heating Value Diesel Fuel	Btu/gal	137,000
Maximum Heat Input	MMBtu/hr	2.06
number of engines		1
annual hours of operation		100

Emissions Fire Pump

Air Toxic	Emission Factor lb/MMBtu	lb/hr	ton/yr	HAPs	HAP ton/yr
1,3-Butadiene	3.91E-05	8.04E-05	4.02E-06	HAP	4.02E-06
2-Methylnaphthalene	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Acetaldehyde	7.67E-04	1.58E-03	7.88E-05	HAP	7.88E-05
Acrolein	9.25E-05	1.90E-04	9.50E-06	HAP	9.50E-06
Anthracene	1.87E-06	3.84E-06	1.92E-07	HAP	1.92E-07
Ammonia	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Benzene	9.33E-04	1.92E-03	9.59E-05	HAP	9.59E-05
Benzo(a)anthracene	1.68E-06	3.45E-06	1.73E-07	HAP	1.73E-07
Benzo(a)pyrene	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Butane	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Chrysene	3.53E-07	7.25E-07	3.63E-08	0	0.00E+00
Dibenz(a,h)anthracene	5.83E-07	1.20E-06	5.99E-08	0	0.00E+00
Ethane	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Ethylbenzene	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Formaldehyde	1.18E-03	2.42E-03	1.21E-04	HAP	1.21E-04
Hexane	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Naphthalene	8.48E-05	1.74E-04	8.71E-06	HAP	8.71E-06
Pentane	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Phenanthrene	2.94E-05	6.04E-05	3.02E-06	0	0.00E+00
PAH	1.68E-04	3.45E-04	1.73E-05	HAP	1.73E-05
Propane	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Propylene	2.58E-04	5.30E-04	2.65E-05	0	0.00E+00
Propylene Oxide	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Pyrene	4.78E-06	9.82E-06	4.91E-07	0	0.00E+00
Sulfuric Acid	from vendor info	8.62E-05	4.31E-06	0	0.00E+00
Toluene	4.09E-04	8.40E-04	4.20E-05	HAP	4.20E-05
Xylene (Total)	2.85E-04	5.86E-04	2.93E-05	HAP	2.93E-05
Arsenic	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Barium	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Beryllium	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Cadmium	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Chromium	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Cobalt	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Copper	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Manganese	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Mercury	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Molybdenum	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Nickel	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Selenium	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Vanadium	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Zinc	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00

Hess Newark Energy Center

Air Toxic Emissions

Emergency Generator

	Units	
Maximum Fuel Flow	gal/hr	105
Heating Value Diesel Fuel	Btu/gal	137,000
Maximum Heat Input	MMBtu/hr	14.36
number of engines		1
annual hours of operation		100

Emissions Emergency Generator

	Emission Factor				
Air Toxic	**lb/MMBtu**	**lb/hr**	**ton/yr**	**HAPs**	**HAP ton/yr**
1,3-Butadiene	3.91E-05	5.61E-04	2.81E-05	HAP	2.81E-05
2-Methylnaphthalene	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Acetaldehyde	7.67E-04	1.10E-02	5.51E-04	HAP	5.51E-04
Acrolein	9.25E-05	1.33E-03	6.64E-05	HAP	6.64E-05
Anthracene	1.87E-06	2.68E-05	1.34E-06	HAP	1.34E-06
Ammonia	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Benzene	9.33E-04	1.34E-02	6.70E-04	HAP	6.70E-04
Benzo(a)anthracene	1.68E-06	2.41E-05	1.21E-06	HAP	1.21E-06
Benzo(a)pyrene	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Butane	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Chrysene	3.53E-07	5.07E-06	2.53E-07	0	0.00E+00
Dibenz(a,h)anthracene	5.83E-07	8.37E-06	4.19E-07	0	0.00E+00
Ethane	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Ethylbenzene	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Formaldehyde	1.18E-03	1.69E-02	8.47E-04	HAP	8.47E-04
Hexane	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Naphthalene	8.48E-05	1.22E-03	6.09E-05	HAP	6.09E-05
Pentane	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Phenanthrene	2.94E-05	4.22E-04	2.11E-05	0	0.00E+00
PAH	1.68E-04	2.41E-03	1.21E-04	HAP	1.21E-04
Propane	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Propylene	2.58E-04	3.70E-03	1.85E-04	0	0.00E+00
Propylene Oxide	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Pyrene	4.78E-06	6.86E-05	3.43E-06	0	0.00E+00
Sulfuric Acid	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Toluene	4.09E-04	5.87E-03	2.94E-04	HAP	2.94E-04
Xylene (Total)	2.85E-04	4.09E-03	2.05E-04	HAP	2.05E-04
Arsenic	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Barium	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Beryllium	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Cadmium	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Chromium	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Cobalt	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Copper	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Manganese	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Mercury	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Molybdenum	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Nickel	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Selenium	0.00E+00	0.00E+00	0.00E+00	HAP	0.00E+00
Vanadium	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00
Zinc	0.00E+00	0.00E+00	0.00E+00	0	0.00E+00

Hess Newark Energy Center

Air Toxic Emission Factors

Sources:

CTGs:	*AP-42 - Background Document for Section 3.1 - Table 3.1-3 (factors including CO catalyst control used when available)*
CTGs:	*CARB - CATEF Formaldehyde Emission Factor Database for Natural Gas Fired Turbines with SCR and/or CO catalyst*
CTGs:	*ammonia emissions based on 5 ppmv in exhaust at worst case base load and partial conditions (Case 1A and Case 36/36A)*
Duct Burner/Aux Boiler:	*AP-42 Compilation of Emission Factors - Table 1.4-3 and Table 1.4-4*
Duct Burner/Aux Boiler:	*Ventura County AB2588 combustion emission factor for external combustion equipment - hexane emission factor*
Emergency Fire Pump and Emergency Generator:	*AP-42 Compilation of Emission Factors - Table 3.3-2*

	AP-42 Full Load Emission Factor lb/MMBtu	**AP-42 Emission Factor lb/MMSCF**	**AP-42 Emission Factor lb/MMBtu**		**NYS**		**PAH**
Air Toxic	**Full Load CTGs**	**duct burner/boiler**	**emer. fire pump & emer. generator**	**Column1**	**NJ Risk**	**HAP**	**POM**
1,3-Butadiene	4.30E-07		3.91E-05		NJ Risk	HAP	
2-Methylnaphthalene		2.40E-05					POM
Acetaldehyde	4.00E-05		7.67E-04		NJ Risk	HAP	
Acrolein	5.85E-06		9.25E-05		NJ Risk	HAP	
Anthracene		2.40E-06	1.87E-06		NJ Risk	HAP	PAH
Ammonia	8.00E-03				NJ Risk		
Benzene	1.20E-05	2.10E-03	9.33E-04		NJ Risk	HAP	
Benzo(a)anthracene		1.80E-06	1.68E-06		NJ Risk	HAP	PAH
Benzo(a)pyrene		1.20E-06			NJ Risk	HAP	PAH
Butane		2.10E+00					
Chrysene		1.80E-06	3.53E-07				PAH
Dibenz(a,h)anthracene		1.20E-06	5.83E-07				PAH
Ethane		3.10E+00					
Ethylbenzene	3.20E-05				NJ Risk	HAP	
Formaldehyde	1.10E-04	7.50E-02	1.18E-03		NJ Risk	HAP	
Hexane		4.60E-03			NJ Risk	HAP	
Naphthalene	1.30E-06	6.10E-04	8.48E-05		NJ Risk	HAP	PAH
Pentane		2.60E+00					
Phenanthrene		1.70E-05	2.94E-05				PAH
PAH	2.20E-06	9.43E-05	1.68E-04		NJ Risk	HAP	
Propane		1.60E+00					
Propylene			2.58E-04		NJ Risk		
Propylene Oxide	2.90E-05				NJ Risk	HAP	
Pyrene		5.00E-06	4.78E-06				PAH
Sulfuric Acid					NJ Risk		
Toluene	1.30E-04	3.40E-03	4.09E-04		NJ Risk	HAP	
Xylene (Total)	6.40E-05		2.85E-04		NJ Risk	HAP	
Arsenic		2.00E-04			NJ Risk	HAP	
Barium		4.40E-03			NJ Risk		
Beryllium		1.20E-05			NJ Risk	HAP	
Cadmium		1.10E-03			NJ Risk	HAP	
Chromium		1.40E-03			NJ Risk	HAP	
Cobalt		8.40E-05			NJ Risk	HAP	
Copper		8.50E-04			NJ Risk		
Manganese		3.80E-04			NJ Risk	HAP	
Mercury		2.60E-04			NJ Risk	HAP	
Molybdenum		1.10E-03					
Nickel		2.10E-03			NJ Risk	HAP	
Selenium		2.40E-05			NJ Risk	HAP	
Vanadium		2.30E-03			NJ Risk		
Zinc		2.90E-02					

SIZE	DWG NO	SH	REV
A	384A3307	1	6

THIS DOCUMENT SHALL BE REVISED IN ITS ENTIRETY ALL SHEETS OF THIS DOCUMENT ARE THE SAME REVISION LEVEL AS INDICATED IN THE REVISION BLOCK

REVISIONS

REV	DESCRIPTION	DATE (mm/dd/yyyy)	APPROVED
0	For Use In Design	6/4/2009	
1	For Use In Design	10/26/2010	
2	For Use In Design	11/15/2010	
3	For Use In Design	2/25/2011	
4	For Use In Design	3/10/2011	
5	For Use In Design	7/21/2011	
6	For Use In Design	8/3/2011	

Combined Cycle Systems

Emissions Data

STAG 207FA Combined Cycle Plant

SIGNATURES	DATE (mm/dd/yyyy)
PREPARED BY D. Kolman	6/4/2009
SYSTEM ENGINEER REVIEW K. Estrada	
PROJ ENGRG	
ISSUED	

GE Energy

GENERAL ELECTRIC COMPANY GENERAL
ELECTRIC INTERNATIONAL, INC.
POWER PLANT SYSTEMS

Hess Newark Energy Center

MADE FOR: 301278
MDL - T218

FIRST MADE FOR: Hess Newark Energy Center

SIZE **A**	CAGE CODE **NONE**	DWG NO **384A3307**	
SCALE **NONE**		SHEET 1 of 6	

DT-7N

ENVIRONMENTAL IMPACT INFORMATION

Hess Newark Energy Center
207FA

OPERATING POINT		1	2	3	4	5	6	7	8	9	10
LOAD											
Gas Turbine		Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
Plant Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Gas Turbines Operating		2	2	2	2	2	2	2	2	2	2
SITE CONDITIONS											
Ambient Temp.	°F	-8.0	10.0	29.3	50.0	59.0	70.0	80.0	93.0	105.0	70.0
Ambient Press.	psia	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	55.1	50.7	45.0	45.0	55.1
GT Evaporative Cooler state		off	off	off	off	off	off	off	off	off	ON
GT FUEL											
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
LHV	Btu/lb	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.
HHV/LHV		1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105
Fuel Bound Nitrogen	Wt %	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Sulfur Content	PPMW	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03
GAS TURBINE DATA (PER UNIT)											
Fuel Consumption (LHV)	10^6 Btu/hr	2,089.	2,088.	2,018.	1,915.	1,873.	1,873.	1,818.	1,780.	1,723.	1,881.
DILUENT INJECTION											
Type		None	None	None	None	None	None	None	None	None	None
Flow	10^3 lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EXHAUST GAS											
Flow	10^3 lb/hr	4,481.8	4,460.5	4,328.7	4,153.2	4,079.7	4,137.7	4,032.8	3,901.8	3,777.2	4,087.1
Temp.	°F	1,072.1	1,090.4	1,102.8	1,112.6	1,117.7	1,116.9	1,124.2	1,149.6	1,162.1	1,119.0
GT EXHAUST COMPOSITION (VOL %)											
N2		75.07	75.00	74.87	74.60	74.40	74.18	73.90	73.43	72.67	73.89
Ar		0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.87	0.87	0.88
O2		12.46	12.42	12.41	12.44	12.42	12.48	12.44	12.24	12.07	12.29
CO2		3.95	3.96	3.95	3.90	3.88	3.82	3.80	3.84	3.82	3.88
H2O		7.63	7.73	7.88	8.18	8.41	8.64	8.97	9.62	10.58	9.07
GT EMISSIONS											
NOx	PPMVD at 15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/h as NO2	75.6	75.5	73.0	69.3	67.8	67.7	65.8	64.4	62.3	68.0
CO	PPMVD	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/h	36.6	36.4	35.3	33.8	33.2	33.6	32.7	31.4	30.2	33.1
VOC	PPMVW	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	lb/h as CH4	3.5	3.5	3.4	3.3	3.2	3.3	3.2	3.1	3.0	3.2
Total Particulates (excluding sulfates), lb/h		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
SOx	PPMVD at 15% O2	.1217	.1221	.1216	.1201	.1194	.1176	.1170	.1181	.1176	.1194
	lb/h as SO2	1.164	1.163	1.124	1.067	1.043	1.043	1.013	.9917	.9598	1.047
	lb/h as SO3	.0766	.0765	.0740	.0702	.0686	.0686	.0666	.0652	.0631	.0689
HRSG DATA (PER UNIT)											
Supplementary Fired Operation											
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Burner Fuel	Btu/lb- LHV	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7
Burner heat consumption	10^6 Btu/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCR Operation		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
CO Catalyst		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
STACK GAS											
Flow	10^3 lb/hr	4,481.8	4,460.5	4,328.7	4,153.2	4,079.7	4,137.7	4,032.8	3,901.8	3,777.2	4,087.1
	10^3 ft^3/hr, Actual	73,965.	73,498.	71,176.	68,342.	67,263.	68,601.	66,980.	64,890.	63,158.	67,784.
Temp.	°F	183.9	182.7	180.9	180.6	181.2	184.1	184.4	183.7	184.8	183.4
HRSG EXIT EXHAUST GAS COMPOSITION (VOL %)											
N2		75.07	75.00	74.87	74.60	74.40	74.18	73.90	73.43	72.67	73.89
Ar		0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.87	0.87	0.88
O2		12.46	12.42	12.41	12.44	12.42	12.48	12.44	12.24	12.07	12.29
CO2		3.95	3.96	3.95	3.90	3.88	3.82	3.80	3.84	3.82	3.88
H2O		7.63	7.73	7.88	8.18	8.41	8.64	8.97	9.62	10.58	9.07
EMISSIONS											
NOx	PPMVD at 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h as NO2	16.8	16.8	16.2	15.4	15.1	15.1	14.6	14.3	13.8	15.1
CO	PPMVD	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	ppmvd, ref 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h	10.2	10.2	9.9	9.4	9.2	9.2	8.9	8.7	8.4	9.2
VOC	PPMVW	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1
	ppmvd, ref 15% O2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	lb/h as CH4	2.9	2.9	2.8	2.7	2.6	2.6	2.5	2.5	2.4	2.6
Total Particulates (excluding sulfates), lb/h		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Total Particulates (including sulfates), lb/h		10.0	10.0	10.0	9.9	9.9	9.9	9.9	9.9	9.8	9.9
SOx	PPMVD at 15% O2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	lb/h as SO2	.77	.77	.75	.71	.69	.69	.67	.66	.64	.70
	lb/h as SO3	.56	.56	.54	.52	.51	.51	.49	.48	.47	.51
NH3	PPMVD at 15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/h	16.0	16.0	15.0	15.0	14.0	14.0	14.0	14.0	13.0	14.0

GE Company proprietary

The notes page is an integral part of this document
and must be reviewed prior to use of this data.

David.Kolman
3-Aug-11
Rev. 6

OPERATING POINT		11	12	13	14	15	16	17	18	19	20
LOAD											
Gas Turbine		Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
Plant Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Gas Turbines Operating		2	2	2	2	2	2	2	2	2	2
SITE CONDITIONS											
Ambient Temp.	°F	80.0	93.0	105.0	50.0	59.0	70.0	73.0	93.0	105.0	70.0
Ambient Press.	psia	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693
Ambient Relative Humidity	%	50.7	45.0	45.0	60.0	60.0	55.1	53.8	45.0	45.0	55.1
GT Evaporative Cooler state		ON	ON	ON	off	off	off	off	off	off	ON
GT FUEL											
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
LHV	Btu/lb	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.
HHV/LHV		1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105
Fuel Bound Nitrogen	Wt %	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Sulfur Content	PPMW	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03
GAS TURBINE DATA (PER UNIT)											
Fuel Consumption (LHV)	10^6 Btu/hr	1,888.	1,872.	1,822.	1,915.	1,873.	1,873.	1,856.	1,780.	1,723.	1,881.
DILUENT INJECTION											
Type		None	None	None	None	None	None	None	None	None	None
Flow	10^3 lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EXHAUST GAS											
Flow	10^3 lb/hr	4,140.5	4,039.2	3,925.9	4,153.2	4,079.7	4,137.7	4,105.9	3,901.8	3,777.2	4,087.1
Temp.	°F	1,118.4	1,140.7	1,150.8	1,112.6	1,117.7	1,116.9	1,119.0	1,149.6	1,162.1	1,119.0
GT EXHAUST COMPOSITION (VOL %)											
N2		73.56	72.97	72.16	74.60	74.40	74.18	74.10	73.43	72.67	73.89
Ar		0.88	0.87	0.86	0.89	0.89	0.88	0.88	0.87	0.87	0.88
O2		12.28	12.02	11.82	12.44	12.42	12.48	12.47	12.24	12.07	12.29
CO2		3.84	3.89	3.88	3.90	3.88	3.82	3.81	3.84	3.82	3.88
H2O		9.45	10.25	11.28	8.18	8.41	8.64	8.73	9.62	10.58	9.07
GT EMISSIONS											
NOx	PPMVD at 15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/h as NO2	68.3	67.7	65.9	69.3	67.8	67.7	67.1	64.4	62.3	68.0
CO	PPMVD	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/h	33.4	32.4	31.3	33.8	33.2	33.6	33.3	31.4	30.2	33.1
VOC	PPMVW	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	lb/h as CH4	3.3	3.2	3.1	3.3	3.2	3.3	3.3	3.1	3.0	3.2
Total Particulates (excluding sulfates), lb/h		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
SOx	PPMVD at 15% O2	.1181	.1197	.1194	.1201	.1194	.1176	.1174	.1181	.1176	.1194
	lb/h as SO2	1.052	1.042	1.015	1.067	1.043	1.043	1.034	.9917	.9598	1.047
	lb/h as SO3	.0692	.0686	.0668	.0702	.0686	.0686	.0680	.0652	.0631	.0689
HRSG DATA (PER UNIT)											
Supplementary Fired Operation											
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Burner Fuel	Btu/lb- LHV	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7
Burner heat consumption	10^6 Btu/hr	0.0	0.0	0.0	119.	168.	171.	190.	199.	211.	160.
SCR Operation		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
CO Catalyst		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
STACK GAS											
Flow	10^3 lb/hr	4,140.5	4,039.2	3,925.9	4,159.0	4,087.8	4,146.0	4,115.1	3,911.4	3,787.5	4,094.8
	10^3 ft^3/hr, Actual	69,072.	67,568.	66,076.	67,957.	66,770.	68,026.	67,496.	64,323.	62,551.	67,259.
Temp.	°F	186.1	186.0	187.3	175.5	174.4	176.6	176.0	175.4	175.7	176.4
HRSG EXIT EXHAUST GAS COMPOSITION (VOL %)											
N2		73.56	72.97	72.16	74.42	74.15	73.93	73.82	73.12	72.34	73.65
Ar		0.88	0.87	0.86	0.89	0.88	0.88	0.88	0.87	0.86	0.88
O2		12.28	12.02	11.82	11.94	11.71	11.76	11.67	11.36	11.11	11.61
CO2		3.84	3.89	3.88	4.13	4.21	4.15	4.19	4.24	4.26	4.19
H2O		9.45	10.25	11.28	8.62	9.05	9.28	9.45	10.40	11.42	9.67
EMISSIONS											
NOx	PPMVD at 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h as NO2	15.2	15.0	14.6	16.4	16.4	16.4	16.5	15.9	15.6	16.4
CO	PPMVD	2.5	2.5	2.6	2.7	2.7	2.7	2.7	2.8	2.8	2.7
	ppmvd, ref 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h	9.2	9.2	8.9	10.0	10.0	10.0	10.0	9.7	9.5	10.0
VOC	PPMVW	1.1	1.1	1.1	2.4	2.5	2.4	2.5	2.5	2.5	2.5
	ppmvd, ref 15% O2	1.0	1.0	1.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h as CH4	2.6	2.6	2.6	5.7	5.7	5.7	5.7	5.6	5.4	5.7
Total Particulates (excluding sulfates), lb/h		9.0	9.0	9.0	10.3	10.9	10.9	11.1	11.2	11.3	10.8
Total Particulates (including sulfates), lb/h		9.9	9.9	9.9	11.3	11.9	11.9	12.1	12.2	12.3	11.8
SOx	PPMVD at 15% O2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	lb/h as SO2	.70	.69	.67	.75	.76	.76	.76	.73	.72	.76
	lb/h as SO3	.51	.51	.49	.55	.55	.55	.55	.53	.52	.55
NH3	PPMVD at 15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/h	15.0	14.0	14.0	15.0	14.0	14.0	14.0	14.0	13.0	14.0

GE Company proprietary

David.Kolman
3-Aug-11
Rev. 6

The notes page is an integral part of this document
and must be reviewed prior to use of this data.

OPERATING POINT		21	22	23	24	25	26	27	28	29	30
LOAD											
Gas Turbine		Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
Plant Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	87.7	102.7	107.5
Gas Turbines Operating		2	2	2	2	2	2	2	2	2	2
SITE CONDITIONS											
Ambient Temp.	°F	93.0	105.0	47.6	50.0	59.0	70.0	93.0	105.0	70.0	93.0
Ambient Press.	psia	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693
Ambient Relative Humidity	%	45.0	45.0	60.0	60.0	60.0	55.1	45.0	45.0	55.1	45.0
GT Evaporative Cooler state		ON	ON	off	off	off	off	off	off	ON	ON
GT FUEL											
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
LHV	Btu/lb	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.
HHV/LHV		1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105
Fuel Bound Nitrogen	Wt %	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Sulfur Content	PPMW	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03
GAS TURBINE DATA (PER UNIT)											
Fuel Consumption (LHV)	10^6 Btu/hr	1,872.	1,822.	1,927.	1,915.	1,873.	1,873.	1,780.	1,723.	1,881.	1,872.
DILUENT INJECTION											
Type		None	None	None	None	None	None	None	None	None	None
Flow	10^3 lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EXHAUST GAS											
Flow	10^3 lb/hr	4,039.2	3,925.9	4,173.2	4,153.2	4,079.7	4,137.7	3,901.8	3,777.2	4,087.1	4,039.2
Temp.	°F	1,140.7	1,150.8	1,111.3	1,112.6	1,117.7	1,116.9	1,149.6	1,162.1	1,119.0	1,140.7
GT EXHAUST COMPOSITION (VOL %)											
N2		72.97	72.16	74.64	74.60	74.40	74.18	73.43	72.67	73.89	72.97
Ar		0.87	0.86	0.89	0.89	0.89	0.88	0.87	0.87	0.88	0.87
O2		12.02	11.82	12.44	12.44	12.42	12.48	12.24	12.07	12.29	12.02
CO2		3.89	3.88	3.90	3.90	3.88	3.82	3.84	3.82	3.88	3.89
H2O		10.25	11.28	8.13	8.18	8.41	8.64	9.62	10.58	9.07	10.25
GT EMISSIONS											
NOx	PPMVD at 15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/h as NO2	67.7	65.9	69.7	69.3	67.8	67.7	64.4	62.3	68.0	67.7
CO	PPMVD	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/h	32.4	31.3	34.0	33.8	33.2	33.6	31.4	30.2	33.1	32.4
VOC	PPMVW	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	lb/h as CH4	3.2	3.1	3.3	3.3	3.2	3.3	3.1	3.0	3.2	3.2
Total Particulates (excluding sulfates), lb/h		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
SOx	PPMVD at 15% O2	.1197	.1194	.1202	.1201	.1194	.1176	.1181	.1176	.1194	.1197
	lb/h as SO2	1.042	1.015	1.073	1.067	1.043	1.043	.9917	.9598	1.047	1.042
	lb/h as SO3	.0686	.0668	.0706	.0702	.0686	.0686	.0652	.0631	.0689	.0686
HRSG DATA (PER UNIT)											
Supplementary Fired Operation											
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Burner Fuel	Btu/lb- LHV	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7
Burner heat consumption	10^6 Btu/hr	177.	189.	105.	105.	105.	105.	105.	105.	105.	105.
SCR Operation		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
CO Catalyst		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
STACK GAS											
Flow	10^3 lb/hr	4,047.8	3,935.1	4,178.4	4,158.3	4,084.8	4,142.8	3,906.9	3,782.3	4,092.2	4,044.3
	10^3 ft^3/hr, Actual	66,999.	65,460.	68,290.	67,989.	66,906.	68,203.	64,528.	62,789.	67,400.	67,183.
Temp.	°F	178.3	178.8	175.8	176.0	176.5	179.1	178.7	179.5	178.4	180.9
HRSG EXIT EXHAUST GAS COMPOSITION (VOL %)											
N2		72.71	71.88	74.49	74.44	74.24	74.03	73.27	72.50	73.73	72.82
Ar		0.87	0.86	0.89	0.89	0.88	0.88	0.87	0.86	0.88	0.87
O2		11.27	11.00	12.00	11.99	11.97	12.03	11.78	11.59	11.84	11.57
CO2		4.24	4.26	4.11	4.10	4.09	4.02	4.05	4.04	4.08	4.09
H2O		10.92	12.01	8.52	8.57	8.81	9.03	10.03	11.00	9.46	10.65
EMISSIONS											
NOx	PPMVD at 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h as NO2	16.5	16.2	16.3	16.2	15.9	15.9	15.2	14.7	16.0	15.9
CO	PPMVD	2.8	2.8	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7
	ppmvd, ref 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h	10.0	9.9	9.9	9.9	9.7	9.7	9.2	9.0	9.7	9.7
VOC	PPMVW	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	ppmvd, ref 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h as CH4	5.7	5.6	5.7	5.7	5.5	5.5	5.3	5.1	5.6	5.5
Total Particulates (excluding sulfates), lb/h		11.0	11.1	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Total Particulates (including sulfates), lb/h		12.0	12.1	11.2	11.2	11.1	11.1	11.1	11.1	11.1	11.1
SOx	PPMVD at 15% O2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	lb/h as SO2	.76	.74	.75	.75	.73	.73	.70	.68	.74	.73
	lb/h as SO3	.55	.54	.55	.55	.53	.53	.51	.49	.54	.53
NH3	PPMVD at 15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/h	14.0	14.0	15.0	15.0	14.0	14.0	14.0	13.0	14.0	14.0

The notes page is an integral part of this document
and must be reviewed prior to use of this data.

OPERATING POINT		31	32	33	34	35	36	37	38
LOAD									
Gas Turbine		Base	Part	Part	Part	Part	Part	Part	Part
Plant Load	%	92.5	82.8	78.8	73.9	79.0	61.2	54.0	52.9
Gas Turbines Operating		2	2	2	2	2	2	2	2
SITE CONDITIONS									
Ambient Temp.	°F	105.0	-8.0	59.0	105.0	-8.0	59.0	93.0	105.0
Ambient Press.	psia	14.693	14.693	14.693	14.693	14.693	14.693	14.693	14.693
Ambient Relative Humidity	%	45.0	60.0	60.0	45.0	60.0	60.0	45.0	45.0
GT Evaporative Cooler state		ON	off	off	off	off	off	off	off
GT FUEL									
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG
LHV	Btu/lb	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.	20,577.
HHV/LHV		1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105	1.1105
Fuel Bound Nitrogen	Wt %	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Sulfur Content	PPMW	6.03	6.03	6.03	6.03	6.03	6.03	6.03	6.03
GAS TURBINE DATA (PER UNIT)									
Fuel Consumption (LHV)	10^6 Btu/hr	1,822.	1,636.	1,499.	1,391.	1,479.	1,139.	1,120.	1,112.
DILUENT INJECTION									
Type		None	None	None	None	None	None	None	None
Flow	10^3 lb/hr	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EXHAUST GAS									
Flow	10^3 lb/hr	3,925.9	3,615.9	3,231.5	3,066.0	3,288.5	2,694.6	2,734.5	2,740.3
Temp.	°F	1,150.8	1,090.5	1,183.0	1,215.0	1,134.8	1,215.0	1,215.0	1,215.0
GT EXHAUST COMPOSITION (VOL %)									
N2		72.16	75.13	74.34	72.66	75.13	74.57	73.66	72.92
Ar		0.86	0.89	0.89	0.86	0.89	0.89	0.88	0.87
O2		11.82	12.63	12.26	12.04	12.64	12.91	12.92	12.82
CO2		3.88	3.87	3.96	3.84	3.87	3.65	3.52	3.47
H2O		11.28	7.48	8.56	10.61	7.47	7.98	9.02	9.92
GT EMISSIONS									
NOx	PPMVD at 15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/h as NO2	65.9	59.8	54.8	50.8	54.3	42.1	41.3	41.0
CO	PPMVD	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
	lb/h	31.3	29.6	26.2	24.5	26.9	22.0	22.2	22.1
VOC	PPMVW	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
	lb/h as CH4	3.1	2.9	2.6	2.4	2.6	2.1	2.2	2.2
Total Particulates (excluding sulfates), lb/h		9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
SOx	PPMVD at 15% O2	.1194	.1181	.1206	.1170	.1174	.1101	.1062	.1048
	lb/h as SO2	1.015	.9112	.8349	.7746	.8237	.6345	.6237	.6191
	lb/h as SO3	.0668	.0599	.0549	.0510	.0542	.0417	.0410	.0407
HRSG DATA (PER UNIT)									
Supplementary Fired Operation									
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG
Burner Fuel	Btu/lb- LHV	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7	20,577.7
Burner heat consumption	10^6 Btu/hr	105.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCR Operation		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
CO Catalyst		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
STACK GAS									
Flow	10^3 lb/hr	3,931.0	3,615.9	3,231.5	3,066.0	3,288.5	2,694.6	2,734.5	2,740.3
	10^3 ft^3/hr, Actual	65,682.	58,824.	52,146.	50,350.	53,003.	43,002.	44,248.	44,726.
Temp.	°F	182.1	175.0	167.4	173.2	169.1	161.3	167.1	170.3
HRSG EXIT EXHAUST GAS COMPOSITION (VOL %)									
N2		72.00	75.13	74.34	72.66	75.13	74.57	73.66	72.92
Ar		0.86	0.89	0.89	0.86	0.89	0.89	0.88	0.87
O2		11.36	12.63	12.26	12.04	12.64	12.91	12.92	12.82
CO2		4.09	3.87	3.96	3.84	3.87	3.65	3.52	3.47
H2O		11.69	7.48	8.56	10.61	7.47	7.98	9.02	9.92
EMISSIONS									
NOx	PPMVD at 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h as NO2	15.5	13.3	12.2	11.3	12.1	9.3	9.2	9.1
CO	PPMVD	2.7	2.5	2.5	2.5	2.5	2.3	2.3	2.3
	ppmvd, ref 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/h	9.4	8.1	7.4	6.9	7.3	5.7	5.6	5.5
VOC	PPMVW	2.4	1.1	1.2	1.1	1.1	1.1	1.0	1.0
	ppmvd, ref 15% O2	2.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	lb/h as CH4	5.4	2.3	2.1	2.0	2.1	1.6	1.6	1.6
Total Particulates (excluding sulfates), lb/h		10.2	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Total Particulates (including sulfates), lb/h		11.1	9.8	9.7	9.7	9.7	9.6	9.5	9.5
SOx	PPMVD at 15% O2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	lb/h as SO2	.71	.61	.56	.52	.55	.42	.41	.41
	lb/h as SO3	.52	.44	.40	.38	.40	.31	.30	.30
NH3	PPMVD at 15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/h	14.0	13.0	12.0	11.0	12.0	9.0	9.0	9.0

The notes page is an integral part of this document
and must be reviewed prior to use of this data.

GT Emission Notes

1. Steady-State Operation

2. Gas Turbine SOx Emissions are reported based on an expected 95% fuel sulfur conversion to SO2 and 5% fuel sulfur conversion to SO3.

3. Total Particulates Emissions are Production Rates and Not Release Rates and do not include Sulfuric acid mist.

4. Emissions are based on GE recommended measurement methods.

5. NOx concentration are reported as PPMV on a dry basis and corrected to 15% oxygen without correction to ISO ambient reference heat rate conditions. NOx Mass Flow Emissions (LB/HR) are values at the operating point and are based on the uncorrected NOx concentration.

6. NG = Natural Gas, DO = Distillate Oil, SG = Syngas

HRSG Emission Notes:

1. Steady-State Operation

2. HRSG Stack SOx Emissions are reported for an expected 95% Gas Turbine Sulfur Conversion to SO2 and 5% Conversion to SO3.
The duct burner contributions to Stack Sox Emissions are reported for an expected 95% Duct Burner Consumption Sulfur to SO2 and 5% to SO3

- For installations that are equipped with a CO catalyst it is expected that 10% to about 35% of the SO2 in the exhaust gas is converted to SO3. The actual conversion rate used in these calculations is 30%.

- For installations with an SCR catalyst for NOx abatement it is expected that 1% to 5% of the SO2 in the exhaust gas will be converted to SO3. The actual conversion rate used in these calculations is 5%.

3. HRSG Stack NH3 Emissions are Based on 0% Conversion to Ammonium Salts

4. HRSG Stack Total Particulates Emissions are Production Rates and Not Release Rates. Total Particulates Emissions Do Not Include Contribution of SO3 and/or Ammonium Salt Conversion.
- For installations with an SCR catalyst for NOx abatement Total Particulates emissions are expected to increase due to ammonium salt formation when ammonia (NH3) is injected into the exhaust gas stream.

Additional salt formation is experienced with CO catalysts.

(Estimated maximum PM-10 Emissions including ammonium salt contribution, assuming 5% Conversion of SO2 toSO3 in the SCR and 30% in the CO Catalyst is 12.3 LB/h. Maximum occurs during operation on liquid fuel).

5. Environmental impact information reported above are estimated values based on GE recommended measurements and analysis procedures.

6. NOx concentrations are reported as PPMV on a dry basis and corrected to 15% oxygen without correction to ISO ambient reference heat rate conditions. NOx Mass Flow Emissions (LB/HR) are values at the operating point and are based on the uncorrected NOx concentration

7. HRSG Stack Diameter = 15.00 ft (Assumed Value)

Appendix C

RBLC Tables

RBLC Review for Large Combined Cycle Turbines - CO

RBLC ID	Facility	County	State	Permit Date	Basis	Control	Limit (PPM)	Notes
CT-0151	KLEEN ENERGY SYSTEMS, LLC	Middlesex	CT	2/25/2008	BACT-PSD	CO Catalyst	0.9	1.7 PPMVD @ 15 % O2 with duct burning
*VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	BACT-PSD	Oxidation catalyst	1.3	Without power augmentation
	CPV Valley Energy Center	Wawayanda	NY	NA			2.0	
	Caithness Long Island Energy	New York	NY	NA			2.0	
	Brockton Clean Energy	Brockton	MA	NA			2.0	
TX-0590	KING POWER STATION	Harris	TX	8/5/2010	BACT-PSD	Oxidation catalyst	2.0	
ID-0018	LANGLEY GULCH POWER PLANT	Payette	ID	6/25/2010	BACT-PSD	Oxidation catalyst	2.0	
GA-0138	LIVE OAKS POWER PLANT	Glynn	GA	4/8/2010	BACT-PSD	Oxidation catalyst	2.0	
*TX-0546	PATTILLO BRANCH POWER PLANT	Fannin	TX	6/17/2009	BACT-PSD	Oxidation catalyst	2.0	
NJ-0074	WEST DEPTFORD ENERGY	Gloucester	NJ	5/6/2009	BACT-PSD	Oxidation catalyst	2.0	
MI-0366	BERRIEN ENERGY, LLC	Berrien	MI	4/13/2005	BACT-PSD	Oxidation catalyst	2.0	4.0 PPMVD PER TURBINE/DUCT BURNER SET
OR-0039	COB ENERGY FACILITY, LLC	Klamath	OR	12/30/2003	BACT-PSD	Oxidation catalyst	2.0	
CA-1096	VERNON CITY LIGHT & POWER	Los Angeles	CA	5/27/2003	BACT-PSD	SCR, Oxidation catalyst	2.0	
CA-1097	MAGNOLIA POWER PROJECT, SCPPA	Los Angeles	CA	5/27/2003	BACT-PSD	SCR, Oxidation catalyst	2.0	
WA-0315	SUMAS ENERGY 2 GENERATION FACILITY	Whatcom	WA	4/17/2003	BACT-PSD	Oxidation catalyst	2.0	
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	Effingham	GA	4/17/2003	BACT-PSD	Oxidation catalyst	2.0	
WA-0291	WALLULA POWER PLANT	Walla Walla	WA	1/3/2003	Other	Oxidation catalyst	2.0	
NJ-0043	LIBERTY GENERATING STATION	Union	NJ	3/28/2002	Other	CO Catalyst	2.0	
GA-0102	WANSLEY COMBINED CYCLE ENERGY FACILITY	Heard	GA	1/15/2002	BACT-PSD	Good combustion practices	2.0	
WA-0288	LONGVIEW ENERGY DEVELOPMENT	Cowlitz	WA	9/4/2001	Other	Oxidation catalyst	2.0	
NJ-0058	PSEG FOSSIL LLC LINDEN GENERATING STATION	Union	NJ	8/24/2001	BACT-PSD	Oxidation catalyst	2.0	
NJ-0059	COGEN TECHNOLOGIES LINDEN VENTURE, L.P	Union	NJ	5/9/2001	Other	Oxidation catalyst	2.0	
WA-0302	GOLDENDALE ENERGY PROJECT	Klickitat	WA	2/23/2001	BACT-PSD	Oxidation catalyst	2.0	
NV-0034	LAS VEGAS COGENERATION FACILITY	Clark	NV	11/13/2000	BACT-PSD	Oxidation catalyst	2.0	
MA-0027	CABOT POWER CORPORATION	Suffolk	MA	5/7/2000	BACT-PSD	Oxidation catalyst	2.0	
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	Maricopa	AZ	11/12/2003	BACT-PSD	Oxidation catalyst	3.0	
TX-0600	THOMAS C. FERGUSON POWER PLANT	Llano	TX	9/1/2011	BACT-PSD	Oxidation catalyst	4.0	
NJ-0066	AES RED OAK LLC	Middlesex	NJ	2/16/2006	BACT-PSD	Oxidation catalyst	4.0	
ID-0010	MIDDLETON FACILITY	Canyon	ID	10/19/2001	BACT-PSD	None	5.0	2.0000 PPM @ 15% O2 W/ DB
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	Palm Beach	FL	7/30/2008	BACT-PSD	Good combustion practices	6.0	24-hour standards
TX-0552	WOLF HOLLOW POWER PLANT NO. 2	Hood	TX	3/3/2010	BACT-PSD	Good combustion practices	11.0	GE7FA
TX-0551	PANDA SHERMAN POWER STATION	Grayson	TX	2/3/2010	BACT-PSD	Good combustion practices	15.0	Combined-cycle mode.
*TX-0547	LAMAR POWER PARTNERS II LLC	Lamar	TX	6/22/2009	BACT-PSD	Good combustion practices	15.0	
*TX-0548	MADISON BELL ENERGY CENTER	Madison	TX	8/18/2009	BACT-PSD	Good combustion practices	17.5	
LA-0136	PLAQUEMINE COGENERATION FACILITY	Iberville	LA	7/23/2008	BACT-PSD	Good combustion practices	25.0	

RBLC Review for Large Combined Cycle Turbines - NO_x

Hess Newark Energy Center

RBLC ID	Facility	County	State	Permit Date	Basis	Control	Limit (PPM)	Notes
	CPV Valley Energy Center	Wawayanda	NY	NA	LAER		2.0	
	Caithness Long Island Energy	New York	NY	NA	LAER		2.0	
	Brockton Clean Energy	Brockton	MA	NA			2.0	
ID-0018	LANGLEY GULCH POWER PLANT	Payette	ID	06/25/2010	BACT-PSD	DLN, SCR	2.0	
TX-0600	THOMAS C. FERGUSON POWER PLANT	Llano	TX	9/1/2011	BACT-PSD	DLN, SCR	2.0	
*OR-0048	CARTY PLANT	Morrow	OR	12/29/2010	BACT-PSD	SCR	2.0	
TX-0590	KING POWER STATION	Harris	TX	8/5/2010	LAER	DLN, SCR	2.0	
TX-0552	WOLF HOLLOW POWER PLANT NO. 2	Hood	TX	3/3/2010	BACT-PSD	DLN, SCR	2.0	
TX-0551	PANDA SHERMAN POWER STATION	Grayson	TX	2/3/2010	BACT-PSD	DLN, SCR	2.0	Combined-cycle mode.
*TX-0548	MADISON BELL ENERGY CENTER	Madison	TX	8/18/2009	BACT-PSD	SCR	2.0	
*TX-0547	LAMAR POWER PARTNERS II LLC	Lamar	TX	6/22/2009	BACT-PSD	SCR	2.0	
*TX-0546	PATTILLO BRANCH POWER PLANT	Fannin	TX	6/17/2009	BACT-PSD	SCR	2.0	
NJ-0074	WEST DEPTFORD ENERGY	Gloucester	NJ	5/6/2009	LAER	SCR, Water injection	2.0	
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	Palm Beach	FL	7/30/2008	BACT-PSD	SCR	2.0	24-Hour standards
CT-0151	KLEEN ENERGY SYSTEMS, LLC	Middlesex	CT	2/25/2008	LAER	DLN, SCR	2.0	
*VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	BACT-PSD	Premix, SCR	2.0	
NY-0098	ATHENS GENERATING PLANT	Greene	NY	1/19/2007	LAER	DLN, SCR, ammonia injection	2.0	
NY-0100	EMPIRE POWER PLANT	Rensselaer	NY	6/23/2005	LAER	DLN, SCR	2.0	3.0000 PPMVD AT 15% O2 with duct burning
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	Maricopa	AZ	11/12/2003	BACT-PSD	SCR	2.0	
CA-1096	VERNON CITY LIGHT & POWER	Los Angeles	CA	5/27/2003	BACT-PSD	SCR, catalyst	2.0	
CA-1097	MAGNOLIA POWER PROJECT, SCPPA	Los Angeles	CA	5/27/2003	BACT-PSD	SCR, catalyst	2.0	
WA-0315	SUMAS ENERGY 2 GENERATION FACILITY	Whatcom	WA	4/17/2003	BACT-PSD	DLN, SCR	2.0	
NJ-0058	PSEG FOSSIL LLC LINDEN GENERATING STATION	Union	NJ	8/24/2001	BACT-PSD	DLN, SCR	2.0	
WA-0302	GOLDENDALE ENERGY PROJECT	Klickitat	WA	2/23/2001	BACT-PSD	DLN, SCR	2.0	
NV-0034	LAS VEGAS COGENERATION FACILITY	Clark	NV	11/13/2000	BACT-PSD	SCR, ammonia injection	2.0	
MA-0027	CABOT POWER CORPORATION	Suffolk	MA	5/7/2000	LAER	DLN, SCR	2.0	
GA-0138	LIVE OAKS POWER PLANT	Glynn	GA	4/8/2010	BACT-PSD	DLN, SCR	2.5	
MI-0366	BERRIEN ENERGY, LLC	Berrien	MI	4/13/2005	BACT-PSD	DLN, SCR	2.5	
OR-0039	COB ENERGY FACILITY, LLC	Klamath	OR	12/30/2003	BACT-PSD	DLN, SCR	2.5	
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	Effingham	GA	4/17/2003	BACT-PSD	DLN, SCR	2.5	
WA-0291	WALLULA POWER PLANT	Walla Walla	WA	1/3/2003	Other	SCR	2.5	
NJ-0043	LIBERTY GENERATING STATION	Union	NJ	3/28/2002	Other	SCR	2.5	
WA-0288	LONGVIEW ENERGY DEVELOPMENT	Cowlitz	WA	9/4/2001	Other	SCR	2.5	
NJ-0059	COGEN TECHNOLOGIES LINDEN VENTURE, L.P	Union	NJ	5/9/2001	BACT-PSD	DLN, SCR, ammonia injection	2.5	
NJ-0066	AES RED OAK LLC	Middlesex	NJ	2/16/2006	LAER	SCR	3.0	
GA-0102	WANSLEY COMBINED CYCLE ENERGY FACILITY	Heard	GA	1/15/2002	BACT-PSD	DLN, SCR	3.0	
ID-0010	MIDDLETON FACILITY	Canyon	ID	10/19/2001	BACT-PSD	SCR, catalyst	3.0	3.5000 PPM @ 15% O2 W/ DB
*AK-0071	INTERNATIONAL STATION POWER PLANT	Anchorage	AK	12/20/2010	BACT-PSD	DLN, SCR	5.0	
LA-0136	PLAQUEMINE COGENERATION FACILITY	Iberville	LA	7/23/2008	BACT-PSD	SCR	5.0	

RBLC Review for Large Combined Cycle Turbines - SO_2

RBLC ID	Facility	County	State	Permit Date	Basis	Control	Limit (lb/MMBtu)	Notes
*VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	N/A	Good combustion practices	0.0003	
WA-0302	GOLDENDALE ENERGY PROJECT	Klickitat	WA	2/23/2001	BACT-PSD	Good combustion practices	0.0005	
OK-0129	CHOUTEAU POWER PLANT	Mayes	OK	1/23/2009			0.0006	1.06 lb/hr
WA-0288	LONGVIEW ENERGY DEVELOPMENT	Cowlitz	WA	9/4/2001	Other	Low sulfur fuel	0.0006	
NJ-0059	COGEN TECHNOLOGIES LINDEN VENTURE, L.P	Union	NJ	5/9/2001	Other	(N)	0.0010	
WA-0291	WALLULA POWER PLANT	Walla Walla	WA	1/3/2003	Other	Low sulfur fuel	0.0017	
MA-0027	CABOT POWER CORPORATION	Suffolk	MA	5/7/2000	BACT-PSD	Clean fuels	0.0022	
CT-0151	KLEEN ENERGY SYSTEMS, LLC	Middlesex	CT	2/25/2008	BACT-PSD	(N)	0.0023	4.9 lb/hr
WA-0315	SUMAS ENERGY 2 GENERATION FACILITY	Whatcom	WA	4/17/2003	BACT-PSD	Low sulfur fuel	0.0030	
ID-0010	MIDDLETON FACILITY	Canyon	ID	10/19/2001	BACT-PSD	Low sulfur fuel	0.0031	W/ DB
NJ-0043	LIBERTY GENERATING STATION	Union	NJ	3/28/2002	Other	Low sulfur fuel	0.0040	
NJ-0066	AES RED OAK LLC	Middlesex	NJ	2/16/2006	BACT-PSD	Clean fuels	0.0043	
LA-0136	PLAQUEMINE COGENERATION FACILITY	Iberville	LA	7/23/2008	BACT-PSD	Clean fuels	0.0142	40.7000 LB/H
TX-0600	THOMAS C. FERGUSON POWER PLANT	Llano	TX	9/1/2011	BACT-PSD	Pipeline quality natural gas		27.07 LB/H
NJ-0074	WEST DEPTFORD ENERGY	Gloucester	NJ	5/6/2009	Other	Clean fuels		5.6600 LB/H
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	Palm Beach	FL	7/30/2008	BACT-PSD	Pipeline quality natural gas		2.0000 GR S/100 SCF
NJ-0058	PSEG FOSSIL LLC LINDEN GENERATING STATION	Union	NJ	8/24/2001	BACT-PSD	(N)		2.0000 LB/H
NV-0034	LAS VEGAS COGENERATION FACILITY	Clark	NV	11/13/2000	BACT-PSD	Low sulfur fuel		0.3000 LB/H

RBLC Review for Large Combined Cycle Turbines - PM_{10}

RBLC ID	Facility	County	State	Permit Date	Basis	Control	Limit (lb/MMBtu)	Notes
OK-0129	CHOUTEAU POWER PLANT	Mayes	OK	1/23/2009			0.0035	
CT-0151	KLEEN ENERGY SYSTEMS, LLC	Middlesex	CT	2/25/2008	BACT-PSD	(N)	0.0052	11 LB/HR W/O DB15.2000 LB/H W/ DB
	Caithness Long Island Energy	New York	NY	NA			0.0055	0.0066 W/ DB
OR-0039	COB ENERGY FACILITY, LLC	Klamath	OR	12/30/2003	BACT-PSD	Good combustion practices	0.0061	
NY-0100	EMPIRE POWER PLANT	Rensselaer	NY	6/23/2005			0.0063	
*AK-0071	INTERNATIONAL STATION POWER PLANT	Anchorage	AK	12/20/2010	BACT-PSD	Good combustion practices	0.0066	
	CPV Valley Energy Center	Wawayanda	NY	NA			0.0073	
WA-0291	WALLULA POWER PLANT	Walla Walla	WA	1/3/2003	LAER	Natural gas	0.0080	
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	Effingham	GA	4/17/2003	BACT-PSD	Clean fuels, Good combustion practices	0.0090	
ID-0010	MIDDLETON FACILITY	Canyon	ID	10/19/2001	BACT-PSD	Pollution prevention	0.0093	0.00939 LB/MMBTU W/ DB
NJ-0074	WEST DEPTFORD ENERGY	Gloucester	NJ	5/6/2009	Other	Clean fuels	0.0094	18.6600 LB/H
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	Maricopa	AZ	11/12/2003	BACT-PSD	(N)	0.0097	0.01103 LB/MMBTU W/DB
GA-0102	WANSLEY COMBINED CYCLE ENERGY FACILITY	Heard	GA	1/15/2002	BACT-PSD	Good combustion practices	0.0110	
LA-0224	ARSENAL HILL POWER PLANT	CADDO	LA	3/20/2008			0.0115	24.2 LB/HR
WA-0299	SUMAS ENERGY 2 GENERATION FACILITY	Whatcom	WA	9/6/2002	BACT-PSD	Good combustion practices	0.0115	
LA-0136	PLAQUEMINE COGENERATION FACILITY	Iberville	LA	7/23/2008	BACT-PSD	Clean fuels	0.0116	33.5000 LB/H
MI-0366	BERRIEN ENERGY, LLC	Berrien	MI	4/13/2005	BACT-PSD	Good combustion practices	0.0120	19 LB/HR W/O DOB28.9 LB/H W/ DB
MA-0027	CABOT POWER CORPORATION	Suffolk	MA	5/7/2000	BACT-PSD	Clean fuels	0.0120	
NJ-0058	PSEG FOSSIL LLC LINDEN GENERATING STATION	Union	NJ	8/24/2001	BACT-PSD	(N)	0.0127	21.0000 LB/H
*VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	N/A	Good combustion practices	0.0130	
NJ-0066	AES RED OAK LLC	Middlesex	NJ	2/16/2006	BACT-PSD	Clean fuels	0.0135	
NJ-0043	LIBERTY GENERATING STATION	Union	NJ	3/28/2002	BACT-PSD	None	0.0150	0.0170 LB/MMBTU W/ DB
NJ-0059	COGEN TECHNOLOGIES LINDEN VENTURE, L.P	Union	NJ	5/9/2001	BACT-PSD	(N)	0.0260	
TX-0600	THOMAS C. FERGUSON POWER PLANT	Llano	TX	9/1/2011	BACT-PSD	Pipeline quality natural gas		33.43 LB/H
*OR-0048	CARTY PLANT	Morrow	OR	12/29/2010	BACT-PSD	Clean fuels		2.5 LB/MMCF
TX-0590	KING POWER STATION	Harris	TX	8/5/2010	BACT-PSD	Low ash fuel		11.1 LB/HR
WA-0288	LONGVIEW ENERGY DEVELOPMENT	Cowlitz	WA	9/4/2001	Other	Good combustion practices		10 lb/hr

RBLC Review for Large Combined Cycle Turbines - $PM_{2.5}$

0	Brockton Clean Energy	Brockton	MA	NA			0.0055	0.0066 LB/MMBTU W/ DB
NY-0100	EMPIRE POWER PLANT	Rensselaer	NY	6/23/2005			0.0063	
*AK-0071	INTERNATIONAL STATION POWER PLANT	Anchorage	AK	12/20/2010	BACT-PSD	Good combustion practices	0.0066	
0	Caithness Long Island Energy	New York	NY	NA			0.0073	0.0062 LB/MMBTU W/ DB
TX-0600	THOMAS C. FERGUSON POWER PLANT	Llano	TX	9/1/2011	BACT-PSD	Pipeline quality natural gas		33.43 LB/H
TX-0590	KING POWER STATION	Harris	TX	8/5/2010	BACT-PSD	Low ash fuel		11.1 LB/HR
NJ-0074	WEST DEPTFORD ENERGY	Gloucester	NJ	5/6/2009	Other	Clean fuels		18.6600 LB/H

RBLC Review for Large Combined Cycle Turbines - VOC

RBLC ID	Facility	County	State	Permit Date	Basis	Control	Limit (PPM)	Notes
	CPV Valley Energy Center	Wawayanda	NY	NA	LAER		0.7	1.8 PPM W/ DB
*VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	N/A	Oxidation catalyst	0.7	1.0000 PPMVD WITH DUCT BURNER, 1.4000 PPMVD WITH DUCT BURNER AND POWER AUGMENTATION
NY-0100	EMPIRE POWER PLANT	Rensselaer	NY	6/23/2005	LAER	Oxidation catalyst	1.0	7.0000 PPMDV AT 15 % O2 with duct burning
NJ-0043	LIBERTY GENERATING STATION	Union	NJ	3/28/2002	Other	CO Catalyst	1.0	1.7000 PPMVD @ 15% O2 with duct burner
MA-0027	CABOT POWER CORPORATION	Suffolk	MA	5/7/2000	BACT-PSD	Oxidation catalyst	1.0	
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	Palm Beach	FL	7/30/2008	BACT-PSD	(N)	1.2	
NJ-0059	COGEN TECHNOLOGIES LINDEN VENTURE, L.P	Union	NJ	5/9/2001	Other	(N)	1.2	
MI-0366	BERRIEN ENERGY, LLC	Berrien	MI	4/13/2005	BACT-PSD	Oxidation catalyst	1.6	16 LB/H W/ DUCT BURNING
TX-0590	KING POWER STATION	Harris	TX	8/5/2010	LAER	DLN, oxidation catalyst	1.8	
ID-0010	MIDDLETON FACILITY	Canyon	ID	10/19/2001	BACT-PSD	None	1.8	3.8 PPM W/ DB
NJ-0074	WEST DEPTFORD ENERGY	Gloucester	NJ	5/6/2009	LAER	Oxidation catalyst, Good combustion practices	1.9	
WA-0288	LONGVIEW ENERGY DEVELOPMENT	Cowlitz	WA	9/4/2001	Other	Good combustion practices	1.9	
ID-0018	LANGLEY GULCH POWER PLANT	Payette	ID	06/25/2010	BACT-PSD	Oxidation catalyst	2.0	
TX-0600	THOMAS C. FERGUSON POWER PLANT	Llano	TX	9/1/2011	BACT-PSD	Oxidation catalyst	2.0	
GA-0138	LIVE OAKS POWER PLANT	Glynn	GA	4/8/2010	BACT-PSD	Oxidation catalyst	2.0	
*TX-0546	PATTILLO BRANCH POWER PLANT	Fannin	TX	6/17/2009	BACT-PSD	Oxidation catalyst	2.0	
CA-1096	VERNON CITY LIGHT & POWER	Los Angeles	CA	5/27/2003	BACT-PSD	SCR, Oxidation catalyst	2.0	
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	Effingham	GA	4/17/2003	BACT-PSD	Oxidation catalyst	2.0	
GA-0102	WANSLEY COMBINED CYCLE ENERGY FACILITY	Heard	GA	1/15/2002	BACT-PSD	Good combustion practices	2.0	
OR-0039	COB ENERGY FACILITY, LLC	Klamath	OR	12/30/2003	BACT-PSD	Oxidation catalyst, Good combustion practices	2.4	
*TX-0548	MADISON BELL ENERGY CENTER	Madison	TX	8/18/2009	BACT-PSD	Good combustion practices	2.5	
TX-0552	WOLF HOLLOW POWER PLANT NO. 2	Hood	TX	3/3/2010	BACT-PSD	DLN, SCR	3.0	GE7FA
NJ-0066	AES RED OAK LLC	Middlesex	NJ	2/16/2006	LAER	Oxidation catalyst	3.0	
TX-0551	PANDA SHERMAN POWER STATION	Grayson	TX	2/3/2010	BACT-PSD	DLN, SCR	4.0	Combined-cycle mode.
*TX-0547	LAMAR POWER PARTNERS II LLC	Lamar	TX	6/22/2009	BACT-PSD	Good combustion practices	4.0	
NY-0098	ATHENS GENERATING PLANT	Greene	NY	1/19/2007	LAER	Good combustion practices	4.0	
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	Maricopa	AZ	11/12/2003	BACT-PSD	(N)	4.0	
CT-0151	KLEEN ENERGY SYSTEMS, LLC	Middlesex	CT	2/25/2008	BACT-PSD	(N)	5.0	
WA-0291	WALLULA POWER PLANT	Walla Walla	WA	1/3/2003	Other	Good combustion practices	5.0	
WA-0315	SUMAS ENERGY 2 GENERATION FACILITY	Whatcom	WA	4/17/2003	BACT-PSD	Good combustion practices	5.2	
WA-0302	GOLDENDALE ENERGY PROJECT	Klickitat	WA	2/23/2001	BACT-PSD	Oxidation catalyst, Good combustion practices	6.0	
	Caithness Long Island Energy	New York	NY	NA				3.5 LB/H; 6.1 LB/H W/ DB
	Brockton Clean Energy	Brockton	MA	NA				1.0 LB/H; 2.5 LB/H W/ DB
NJ-0058	PSEG FOSSIL LLC LINDEN GENERATING STATION	Union	NJ	8/24/2001	LAER	Oxidation catalyst		2.1000 LB/H
NV-0034	LAS VEGAS COGENERATION FACILITY	Clark	NV	11/13/2000	BACT-PSD	Oxidation catalyst		2.0000 LB/H

RBLC Review for Large Combined Cycle Turbines - H_2SO_4

Hess Newark Energy Center

RBLC ID	Facility	County	State	Permit Date	Basis	Control	Limit (lb/MMBtu)	Notes
*VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	N/A	Good combustion practices	0.00010	
WA-0302	GOLDENDALE ENERGY PROJECT	Klickitat	WA	2/23/2001	Other	Good combustion practices	0.00010	
WA-0315	SUMAS ENERGY 2 GENERATION FACILITY	Whatcom	WA	4/17/2003	BACT-PSD	Low sulfur fuel	0.00062	
WA-0291	WALLULA POWER PLANT	Walla Walla	WA	1/3/2003	Other	Natural gas	0.00073	
NJ-0043	LIBERTY GENERATING STATION	Union	NJ	3/28/2002	Other	None	0.00243	
NJ-0066	AES RED OAK LLC	Middlesex	NJ	2/16/2006	BACT-PSD	Low sulfur fuel	0.00270	
TX-0600	THOMAS C. FERGUSON POWER PLANT	Llano	TX	9/1/2011	BACT-PSD	Pipeline quality natural gas		13.68 LB/H

RBLC Review for Auxiliary Boiler - CO

Hess Newark Energy Center

RBLC ID	Facility	County	State	Permit Date	Status	Capacity (MMBTU/H)	Basis	Notes	Limit (LB/MMBTU)
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	35.4	Other	COMMERCIAL BOILER	0.0073
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	33.48	Other	COMMERCIAL BOILER	0.0075
IA-0062	EMERY GENERATING STATION	Cerro Gordo	IA	12/20/2002	Operational	68	Other	AUX BOILER	0.0164
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	31.38	Other	COMMERCIAL BOILER	0.0172
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	16.8	Other	COMMERCIAL BOILER	0.0173
NV-0050	MGM MIRAGE	Clark	NV	11/30/2009		41.64	LAER	BOILER	0.0184
MD-0040	CPV ST CHARLES	Charles	MD	11/12/2008	Not constructed	93	BACT	AUX BOILER	0.02
NM-0042	DEMING ENERGY FACILITY	Luna	NM	12/29/2000		44.1	BACT	AUX BOILER	0.022
* VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	Draft	97	N/A	AUX BOILER	0.036
NV-0044	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	1/4/2007		35.4	BACT	INDUSTRIAL BOILERS	0.036
WI-0226	WPS - WESTON PLANT	Marathon	WI	8/27/2004	Operational	46.2	N/A	BOILER	0.036
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	24	Other	COMMERCIAL BOILER	0.037
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	8.37	Other	COMMERCIAL BOILER	0.037
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	Lawrence	OH	12/28/2004	Operational	30.6	BACT	BOILERS	0.037
OH-0252	DUKE ENERGY HANGING ROCK	Lawrence	OH	12/28/2004	Operational	30.6	BACT	BOILERS	0.037
WA-0292	SATSOP COMBUSTION TURBINE PROJECT	Grays Harbor	WA	10/23/2001		29.3	BACT	AUX BOILER	0.037
LA-0240	FLOPAM INC.	Iberville	LA	6/14/2010		25.1	BACT	BOILER	0.037
* AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	Mobile	AL	8/17/2007	Draft	64.9	BACT	BOILERS	0.04
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	14.34	Other	COMMERCIAL BOILER	0.0705
TX-0501	TEXSTAR GAS PROCESS FACILITY	Henderson	TX	7/11/2006		93	BACT	INDUSTRIAL BOILERS	0.076
FL-0285	PROGRESS BARTOW POWER PLANT	Pinellas	FL	1/26/2007	Operational	99	BACT	AUX BOILER	0.08
FL-0286	FPL WEST COUNTY ENERGY CENTER	Palm Beach	FL	1/10/2007	Not constructed	99.8	BACT	AUX BOILER	0.08
WI-0227	PORT WASHINGTON GENERATING STATION	Washington	WI	10/13/2004	Operational	97.1	BACT	AUX BOILER	0.08
* OH-0323	TITAN TIRE CORPORATION OF BRYAN	Williams	OH	6/5/2008	Draft	50.4	BACT	BOILER	0.082
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	Lucas	OH	5/3/2007		20.4	BACT	INDUSTRIAL BOILERS	0.083
MN-0053	FAIRBAULT ENERGY PARK	Rice	MN	7/15/2004	Operational	40	BACT	AUX BOILER	0.084
OK-0129	CHOUTEAU POWER PLANT	Mayes	OK	1/23/2009		33.5	N/A	AUX BOILER	0.15
CA-1127	GENENTECH, INC.	San Mateo	CA	9/27/2005		97	BACT	COMMERCIAL BOILER	50.0000 PPMVD @ 3% O2

RBLC Review for Auxiliary Boiler - NO_x

Hess Newark Energy Center

RBLC ID	Facility	County	State	Permit Date	Status	Capacity (MMBTU/H)	Basis	Notes	Limit (LB/MMBTU)
CA-0946	LACORR PACKAGING	Los Angeles	CA	7/12/2000		21	LAER	BOILER	0.009
OK-0055	MUSTANG ENERGY PROJECT	Canadian	OK	2/12/2002	Operational	31	Other	AUX BOILER	0.01
CA-1006	HI-COUNTRY	Riverside	CA	12/16/1999		20.9	BACT	BOILER	0.01
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	24	BACT	COMMERCIAL BOILER	0.0108
MD-0040	CPV ST CHARLES	Charles	MD	11/12/2008	Not constructed	93	LAER	AUX BOILER	0.011
* MD-0037	MEDIMMUNE FREDERICK CAMPUS	Frederick	MD	1/28/2008		29.4	LAER	BOILERS	0.011
* VA-038	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	Draft	97	N/A	AUX BOILER	0.011
CA-0940	NATION WIDE BOILER	Alameda	CA	3/15/2000		28.8	LAER	BOILER, PORTABLE	0.011
NV-0050	MGM MIRAGE	Clark	NV	11/30/2009		41.64	Other	BOILER	0.011
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	8.37	BACT	COMMERCIAL BOILER	0.0146
LA-0240	FLOPAM INC.	Iberville	LA	6/14/2010		25.1	LAER	BOILER	0.015
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	16.8	BACT	COMMERCIAL BOILER	0.03
NM-0042	DEMING ENERGY FACILITY	Luna	NM	12/29/2000		44.1	BACT	AUX BOILER	0.03
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	31.38	BACT	COMMERCIAL BOILER	0.0306
* AK-0071	INTERNATIONAL STATION POWER PLANT	Anchorage	AK	12/20/2010		12.5	BACT	AUXILIARY HEATER	0.031
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	35.4	BACT	COMMERCIAL BOILER	0.035
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	Lucas	OH	5/3/2007		20.4	LAER	INDUSTRIAL BOILERS	0.035
NV-0044	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	1/4/2007		35.4	BACT	INDUSTRIAL BOILERS	0.035
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	Lawrence	OH	12/28/2004	Operational	30.6	BACT	BOILERS	0.035
NV-0037	COPPER MOUNTAIN POWER	Clark	NV	5/14/2004	Not constructed	60	BACT	AUX BOILER	0.035
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	14.34	BACT	COMMERCIAL BOILER	0.0353
WI-0226	WPS - WESTON PLANT	Marathon	WI	8/27/2004	Operational	46.2	N/A	BOILER	0.036
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	33.48	BACT	COMMERCIAL BOILER	0.0367
* NH-0015	CONCORD STEAM CORPORATION	Merrimack	NH	2/27/2009	Draft	76.8	LAER	AUX BOILER (<700 hours/yr)	0.049
OH-0323	TITAN TIRE CORPORATION OF BRYAN	Williams	OH	6/5/2008		50.4	BACT	BOILER	0.049
OR-0048	CARTY PLANT	Morrow	OR	12/29/2010		91	BACT	BOILER	0.049
* OK-0135	PRYOR PLANT CHEMICAL	Mayes	OK	2/23/2009	Draft	80	BACT	BOILERS	0.05
FL-0286	FPL WEST COUNTY ENERGY CENTER	Palm Beach	FL	1/10/2007	Not constructed	99.8	BACT	AUX BOILER	0.05
* OK-0129	CHOUTEAU POWER PLANT	Mayes	OK	1/23/2009	Draft	33.5	BACT	AUX BOILER	0.07
LA-0244	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	Calcasieu	LA	11/29/2010		21	BACT	START HEATER - BACT DETERMINED 19	0.129

RBLC Review for Auxiliary Boiler - SO$_2$

Hess Newark Energy Center

RBLC ID	Facility	County	State	Permit Date	Status	Capacity (MMBTU/H)	Basis	Notes	Limit (LB/MMBTU)
* NY-0095	CAITHNES BELLPORT ENERGY CENTER	Suffolk	NY	5/10/2006	Draft	29.4	BACT	AUX BOILER	0.0005
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	33.48	Other	COMMERCIAL BOILER	0.0006
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	35.4	Other	COMMERCIAL BOILER	0.0006
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	31.83	Other	COMMERCIAL BOILER	0.0006
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	14.34	Other	COMMERCIAL BOILER	0.0006
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	24	Other	COMMERCIAL BOILER	0.0006
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	8.37	Other	COMMERCIAL BOILER	0.0006
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	16.7	Other	COMMERCIAL BOILER	0.0006
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	Lucas	OH	5/3/2007		20.4	BACT	INDUSTRIAL BOILERS	0.0006
WI-0227	PORT WASHINGTON GENERATING STATION	Washington	WI	10/13/2004	Operational	97.1	BACT	AUX BOILER	0.0006
AR-0077	BLUEWATER PROJECT	Mississippi	AR	7/22/2004		22	BACT	BOILERS	0.0006
IN-0108	NUCOR STEEL	Montgomery	IN	11/21/2003		34	BACT	BOILER	0.0006
IA-0062	EMERY GENERATING STATION	Cerro Gordo	IA	12/20/2002	Operational	68	Other	AUX BOILER	0.0006
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	St. Joseph	IN	12/7/2001	Not constructed	21	BACT	AUX BOILER	0.0006
OH-0251	CENTRAL SOYA COMPANY INC.	Huron	OH	11/29/2001		91.2	BACT	BOILER	0.0006
IN-0087	DUKE ENERGY, VIGO LLC	Vigo	IN	6/6/2001	Not constructed	46	BACT	AUX BOILER	0.0006
IN-0086	MIRANT SUGAR CREEK, LLC	Vigo	IN	5/9/2001	Operational	35	BACT	AUX BOILER	0.0006
OH-0255	AEP WATERFORD ENERGY LLC	Washington	OH	3/29/2001	Operational	85.2	BACT	BOILER	0.0006
NV-0050	MGM MIRAGE	Clark	NV	11/30/2009		41.64	BACT	BOILER	0.0007
* OK-0129	CHOUTEAU POWER PLANT	Mayes	OK	1/23/2009	Draft	33.5	N/A	AUX BOILER	0.0009
NV-0044	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	1/4/2007		35.4	BACT	INDUSTRIAL BOILERS	0.001
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	Lawrence	OH	12/28/2004	Operational	30.6	BACT	BOILERS	0.001
MN-0054	MANKATO ENERGY CENTER	Blue Earth	MN	12/4/2003	Not constructed	70	BACT	COMMERCIAL BOILER	0.001
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	Washington	OH	8/14/2003	Operational	30.6	BACT	BOILER	0.001
VA-0255	VA POWER - POSSUM POINT	Prince William	VA	11/18/2002	Operational	99	Other	AUX BOILER	0.001
OK-0071	MCCLAIN ENERGY FACILITY	McClain	OK	10/25/2001	Operational	22	BACT	AUX BOILER	0.001
OH-0265	DRESDEN ENERGY LLC	Muskingum	OH	10/16/2001	Not constructed	49	BACT	BOILER	0.001
AL-0168	GENPOWER KELLEY LLC	Walker	AL	1/12/2001	Not constructed	83	BACT	BOILER	0.001
AZ-0047	WELLTON MOHAWK GENERATING STATION	Yuma	AZ	12/1/2004	Not constructed	38	BACT	AUX BOILER	0.0023
* OK-0135	PRYOR PLANT CHEMICAL	Mayes	OK	2/23/2009	Draft	80	BACT	BOILERS	0.0025
* VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	Draft	97	N/A	AUX BOILER	0.003
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	16.8	Other	COMMERCIAL BOILER	0.0042
FL-0286	FPL WEST COUNTY ENERGY CENTER	Palm Beach	FL	1/10/2007	Not constructed	99.8	BACT	AUX BOILER	2 GS/100 SCF

RBLC Review for Auxiliary Boiler - PM_{10}

RBLC ID	Facility	County	State	Permit Date	Status	Capacity (MMBTU/H)	Basis	Notes	Limit (LB/MMBTU)
OH-0323	TITAN TIRE CORPORATION OF BRYAN	Williams	OH	6/5/2008		50.4	N/A	BOILER	0.0019
* NY-0095	CAITHNES BELLPORT ENERGY CENTER	Suffolk	NY	5/10/2006	Draft	29.4	BACT	AUX BOILER	0.0033
AZ-0047	WELLTON MOHAWK GENERATING STATION	Yuma	AZ	12/1/2004	Not constructed	38	BACT	AUX BOILER	0.0033
OR-0040	KLAMATH GENERATION, LLC	Klamath	OR	3/12/2003		(50000 LB/H)	BACT	AUX BOILER	0.0042
MD-0040	CPV ST CHARLES	Charles	MD	11/12/2008	Not constructed	93	BACT	AUX BOILER	0.005
LA-0240	FLOPAM INC.	Iberville	LA	6/14/2010		25.1	BACT	BOILER	0.005
* OK-0135	PRYOR PLANT CHEMICAL	Mayes	OK	2/23/2009	Draft	80	BACT	BOILERS	0.0063
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	33.48	Other	COMMERCIAL BOILER	0.0075
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	14.34	Other	COMMERCIAL BOILER	0.0075
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	8.37	Other	COMMERCIAL BOILER	0.0075
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	24	Other	COMMERCIAL BOILER	0.0075
OH-0309	TOLEDO SUPPOLIER PARK- PAINT SHOP	Lucas	OH	5/3/2007		20.4	BACT	INDUSTRIAL BOILERS	0.0075
NV-0044	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	1/4/2007		35.4	BACT	INDUSTRIAL BOILERS	0.0075
WI-0228	WPS - WESTON PLANT	Marathon	WI	10/19/2004	Operational	229.8	BACT	AUX BOILER	0.0075
* AK-0071	INTERNATIONAL STATION POWER PLANT	Anchorage	AK	12/20/2010		12.5	BACT	AUXILIARY HEATER	0.0075
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	35.4	Other	COMMERCIAL BOILER	0.0076
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	31.38	Other	COMMERCIAL BOILER	0.0076
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	21	Other	COMMERCIAL BOILER	0.0076
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	16.8	Other	COMMERCIAL BOILER	0.0077
NV-0050	MGM MIRAGE	Clark	NV	11/30/2009		41.64	Other	BOILER	0.0077
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	21	Other	COMMERCIAL BOILER	0.0078
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	Lawrence	OH	12/28/2004	Operational	30.6	BACT	BOILERS	0.01
LA-0244	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	Calcasieu	LA	11/29/2010		21	BACT	START HEATER - BACT DETERMINED 19	0.01
FL-0286	FPL WEST COUNTY ENERGY CENTER	Palm Beach	FL	1/10/2007	Not constructed	99.8	BACT	AUX BOILER	2.0000 G S/100 SCF GAS
OR-0048	CARTY PLANT	Morrow	OR	12/29/2010		91	BACT	BOILER	2.5 LB/MMCF

RBLC Review for Auxiliary Boiler - VOC

Hess Newark Energy Center

RBLC ID	Facility	County	State	Permit Date	Status	Capacity (MMBTU/H)	Basis	Notes	Limit (LB/MMBTU)
MD-0040	CPV ST CHARLES	Charles	MD	11/12/2008	Not constructed	93	LAER	AUX BOILER	0.002
NV-0050	MGM MIRAGE	Clark	NV	11/30/2009		41.64	Other	BOILER	0.0024
IN-0108	NUCOR STEEL	Montgomery	IN	11/21/2003		34	BACT	INDUSTRIAL BOILERS	0.0026
LA-0240	FLOPAM INC.	Iberville	LA	6/14/2010		25.1	BACT	BOILER	0.003
AZ-0047	WELLINGTON MOHAWK GENERATING STATION	Yuma	AZ	12/1/2004	Not constructed	38	BACT	AUX BOILER	0.0033
GA-0098	RINCON POWER PLANT	Effingham	GA	3/24/2003	Not constructed	83	Other	AUX BOILER	0.004
VA-0255	VA POWER - POSSUM POINT	Prince William	VA	11/18/2002	Operational	99	Other	AUX BOILER	0.004
AL-0179	TENASKA TALLADEGA GENERATING STATION	Talladega	AL	10/3/2001	Not constructed	30	BACT	AUX BOILER	0.004
OH-0255	AEP WATERFORD ENERGY LLC	Washington	OH	3/29/2001	Operational	85.2	BACT	AUX BOILER	0.0041
NV-0044	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	1/4/2007		35.4	BACT	INDUSTRIAL BOILERS	0.005
OK-0046	THUNDERBIRD POWER PLT	Cleveland	OK	5/17/2001	Not constructed	20	BACT	AUX BOILER	0.005
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	35.4	Other	COMMERCIAL BOILER	0.0054
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	33.48	Other	COMMERCIAL BOILER	0.0054
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	31.38	Other	COMMERCIAL BOILER	0.0054
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	16.8	Other	COMMERCIAL BOILER	0.0054
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	8.37	Other	COMMERCIAL BOILER	0.0054
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	24	Other	COMMERCIAL BOILER	0.0054
* NV-0049	HARRAH'S OPERATING COMPANY, INC.	Clark	NV	8/20/2009	Draft	14.34	Other	COMMERCIAL BOILER	0.0054
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	Lucas	OH	5/3/2007		20.4	LAER	INDUSTRIAL BOILERS	0.0054
IA-0062	EMERY GENERATING STATION	Cerro Gordo	IA	12/20/2002	Operational	68	Other	AUX BOILER	0.0054
NC-0094	GENPOWER EARLEYS, LLC	Hertford	NC	1/9/2002	Not constructed	83	BACT	AUX BOILER	0.0054
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	St. Joseph	IN	12/7/2001	Not constructed	21	BACT	AUX BOILER	0.0054
IN-0087	DUKE ENERGY, VIGO LLC	Vigo	IN	6/6/2001	Not constructed	46	BACT	AUX BOILER	0.0054
IN-0086	MIRANT SUGAR CREEK, LLC	Vigo	IN	5/9/2001	Operational	35	BACT	AUX BOILER	0.0054
WI-0227	PORT WASHINGTON GENERATING STATION	Washington	WI	10/13/2004	Operational	97.1	BACT	AUX BOILER	0.00545829
MS-0085	Dart Container Corporation	Clarke	MS	1/31/2007		33.5	BACT	NATURAL GAS FIRED BOILER	0.0055
VA-0308	WARREN COUNTY FACILITY	Warren	VA	1/14/2008	Not constructed	97	N/A	AUX BOILER	0.005979381
OH-0252	DUKE ENERGY HANGING ROCK	Lawrence	OH	12/28/2004	Operational	30.6	BACT	BOILERS	0.016

RBLC Review for Auxiliary Boiler - H_2SO_4

Facility	County	State	Permit Date	Status	Capacity (MMBTU/H)	Basis	Notes	Limit (LB/MMBTU)
CPV ST CHARLES	Charles	MD	11/12/2008	Not constructed	93	BACT	AUX BOILER	0.0001
WPS - WESTON PLANT	Marathon	WI	10/19/2004	Operational	229.8	BACT	natural gas heaters	0.0001 lb/MMBtu
MANKATO ENERGY CENTER	Blue Earth	MN	12/4/2003	Not constructed	70	BACT	BOILER	0.8 G S/100 SCF GAS