State of New Jersey

CHRIS CHRISTIE
Governor

DEPARTMENT of ENVIRONMENTAL PROTECTION

BOB MARTIN
Commissioner

FACT SHEET

FOR

R C Cape May, LLC; B. L. England Generating Station

900 North Shore Rd, Beesley's Point
Cape May County, New Jersey 08223

Program Interest (PI) Number: 73242 Permit Activity Number: BOP120001

APPLICATION FOR

SIGNIFICANT MODIFICATION TO AIR POLLUTION CONTROL OPERATING PERMIT (TITLE V)
AND
FEDERAL PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY (PSD) PERMIT
AND
MODIFICATION TO ACID RAIN PERMIT

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Date: 2/5/13

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Date: 2/5/13

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Memorandum of the air dispersion modeling and risk assessment summary

A. FACILITY AND PROJECT DESCRIPTION

R C Cape May (RCCM), B.L. England Generating Station submitted an application on August 16, 2012 for a Federal Prevention of Significant Deterioration of Air Quality (PSD) permit, a Significant Modification to the Title V State Operating Permit and a modification to the Acid Rain permit to replace 440 MW of coal and oil fired electric generating units (EGUs) with gas fired EGUs. Replacement units would include a (nominal) 430-MW natural gas fired combined-cycle unit, increasing the plant capacity to 580 MW. B. L. England Generating Station is located at 900 North Shore Rd, Beesley's Point, Cape May County, New Jersey, 08223. Construction of the Project is scheduled to be completed within 30 months after receiving the final air permit approvals.

The proposed Project will consist of one combined-cycle combustion turbine (CCCT) comprised of one Siemens STG6-8000H combined-cycle combustion turbine generator (CTG), one heat recovery steam generator (HRSG) equipped with duct burner, one existing steam turbine electric generator (STG); and one auxiliary boiler.

The facility will retire existing coal fired Unit 1 and Unit 2 by September 30, 2013 and May 1, 2015, respectively. Additionally, the facility will voluntarily convert existing Unit 3 from No. 6 oil firing to natural gas.

The CTG and duct burner will use only natural gas as fuel. The combustion turbine will have a maximum rated heat input of 2,908 million British thermal units per hour (MM Btu/hr) at an ambient temperature of -8 degrees Fahrenheit (°F), based on high heating value of fuel (HHV) (not including supplemental duct-firing). Supplemental duct firing will add up to 400 MM Btu/hr. Total heat input would be limited to 3,027 MM Btu/hr (HHV). The nominal electrical output of the CCCT is 430 MW at ISO conditions, including the steam turbine output. Combined-cycle electric output and fuel use will vary with ambient temperature, relative humidity and certain other operating conditions such as the amount of duct firing in the HRSG. Ancillary equipment will include a new 91.6-MM Btu/hr auxiliary boiler.

Unit 3 is currently limited to 1,720 MM Btu/hr while firing No. 6 fuel oil. The maximum heat input would be 1,792.5 MM Btu/hr once it is converted to natural gas, and annual operation would be limited to the equivalent heat input of 1,200 hours per year at full load (2,151,000 MM Btu/year). This is a reduction from the current 15,067,200 allowable heat input based on 8760 hours per year operation.

B. AIR QUALITY AND CURRENT AIR CONTAMINANT EMISSIONS

B L England Generating Station is located in Cape May County which is designated as attainment for National Ambient Air Quality Standards (NAAQS) for the criteria pollutants. Nitrogen Oxides (NO_x), Carbon Monoxide (CO), Sulfur Dioxide (SO_2), Total Suspended Particulate (TSP), Particulate Matter less than 10 microns (PM_{10}), Particulate Matter less than 2.5 microns ($PM_{2.5}$) and lead. It is designated as non-attainment for the 75 Parts Per Billion (PPB) 8 -hour ozone NAAQS.

Table 1 lists proposed maximum allowable emissions of criteria pollutants, ammonia, formaldehyde, and greenhouse gases (GHG) from the new combined-cycle unit in pounds per hour (lbs/hr), parts per million by volume dry basis at 15% oxygen (ppmvd @ 15% O_2), and pounds per million British thermal units (lbs/MM Btu). The proposed emission limits from the CCCT would be achieved by the application of air pollution control technologies that are discussed in Section C.

Table 2 lists the existing permit limits for Unit No. 3 No. 6 fuel oil fired and proposed limit after conversion to natural gas.

APPLICABLE RULES:

1. Operating Permit: Based on the potential annual emissions in Table 3 (given in tons per year) the facility is classified as a major source. Hence, B. L. England continues to require an operating permit.

2. PSD: PSD applies to a major modification at an existing major source (the B L England Station) located in an attainment or unclassifiable area with respect to NAAQS, where the proposed potential emissions or net increase of emissions equal or exceed the PSD significance thresholds.

Table 3 is a PSD applicability determination table that shows PSD netting analysis using 2008-2009 past actual emissions. It includes the potential annual emissions of criteria pollutants, sulfuric acid mist and GHG in tons per year (tpy) for the Project and the net emissions resulting from the addition of the Project.

The Project is considered a major modification to an existing major Title V source and because of increase in CO and GHG emissions from the Project, it becomes a major PSD source. The PSD significance thresholds for CO and GHG emissions are 100 tpy and 75,000 tpy, respectively. Increase in CO is 134.8 tpy and the maximum increase in GHG emissions from the project is 869,324 tpy. Hence, the Project is determined to be subject to PSD review and BACT requirements for CO and GHG.

3. NNSR: Table 4 is a NNSR applicability determination table that lists the criteria pollutants emission and $PM_{2.5}$ using 2010-2011 past actual emissions from the facility and applicability of N.J.A.C. 7:27-18 (Subchapter 18 Control and Prohibition of Air Pollution from New or Altered Sources Affecting Ambient Air Quality (Emission Offset Rules). As shown in Table 4, the facility is not subject to Nonattainment New Source Review requirements for any criteria pollutant.

4. SOTA: The facility is also required to meet State of the Art Air Pollution Control Technology (SOTA) of New Jersey Air Pollution Control Regulations (N.J.A.C. 7:27-22.35). SOTA includes performance limits that are based on air pollution control technology, pollution prevention methods, and process modifications or substitutions that will provide the greatest emission reductions that are technologically and economically feasible. Satisfying PSD BACT requirements also satisfies SOTA requirements.

The Hazardous Air Pollutant (HAP) emissions from the facility are included in Attachment I (memorandum of the air dispersion modeling and risk assessment summary from Bureau of Technical Services).

TABLE 1

MAXIMUM ALLOWABLE EMISSIONS FOR COMBUSTION TURBINE/HRSG UNIT
(Operating Conditions: 100% load; CT Operations with HRSG Supplemental Duct-firing)

Air Contaminant units	Maximum Allowable Emissions
Nitrogen Oxides (as NO_2)	
lbs/hr[1]	22.6
ppmvd @ 15% O_2[2]	2.00
Carbon Monoxide (CO)	
lbs/hr	17.2
ppmvd @ 15% O_2	2.50
Volatile Organic Compounds (VOCs)[3]	
lbs/hr	5.90
ppmvd @ 15% O_2	1.50
Sulfur Oxides (SO_2)	
lbs/hr	6.78
PM/Total Suspended Matter (TSP)	
lbs/hr	20.6
lbs/MM Btu	0.00700 (0.00780 without duct firing)
Particulate Matter less than 10 microns (PM_{10})	
lbs/hr	20.6
lbs/MM Btu	0.00700 (0.00780 without duct firing)
Particulate Matter less than 2.5 microns ($PM_{2.5}$)	
lbs/hr	20.6
lbs/MM Btu	0.00700 (0.0078 without duct firing)
Ammonia (NH_3)	
ppmvd @ 15% O_2	5.00
Formaldehyde	
lbs/hr	1.76
CO2e (for Greenhouse Gases)	
lbs/hr	375,348

NOTES:
1. lbs/hr = Pounds per hour.
2. ppmvd (@ 15% O_2) = parts per million by volume on a dry basis (corrected to 15 percent oxygen).
3. lbs/MM Btu = pounds per million British Thermal Units

TABLE 2
MAXIMUM ALLOWABLE EMISSIONS FOR UNIT NO. 3
(Operating Conditions: 100% load; Emissions Before and After Conversion to Nat. Gas)

Air Contaminant units	Maximum Allowable Emissions	
	Current (No. 6 Oil)	Proposed (Nat. Gas)
Nitrogen Oxides (as NO_2) lbs/hr[1]	344	152
Carbon Monoxide (CO) lbs/hr	300	148
Volatile Organic Compounds (VOCs) lbs/hr	23.0	9.67
Sulfur Oxides (SO_2) lbs/hr	1,803	4.02
PM/Total Suspended Matter (TSP) lbs/hr	172	3.34
Particulate Matter less than 10 microns (PM_{10}) lbs/hr	506	13.4
Particulate Matter less than 2.5 microns ($PM_{2.5}$) lbs/hr	No existing limit	13.4
CO2e (for Greenhouse Gases) lbs/hr	No existing limit	210,881

NOTES: 1. lbs/hr = Pounds per hour.

THE FOLLOWING TABLE 3 AND 4 ARE PROVIDED BY THE APPLICANT AS A PART OF THE APPLICATION.

TABLE 3
PSD NETTING ANALYSIS

Emissions Netting for PSD - Gas Only with Startup/Shutdown - Using 2008-2009 Past Actual Emissions[1]									
Pollutant	New CCCT Potential Emissions[2]	New Aux Boiler Potential Emissions[3]	Unit 3 Boiler Net Emissions Change[4]	Unit 8 Cool Tower Net Emissions Change[5]	Units 1 & 2 Boilers Past Actual Emissions[6]	Unit 7 Fuel Handling Past Actual Emissions[7]	Total Net Emissions Increase[8]	New Source Review[9]	
	IA_1-CCCT	IA_2-AB	IA_3-U3	IA_4-U8	DC_1-1,2	DC_2-7	$NI = IA_{1-4} + DC_{1-2}$	PSD Significant Net Emission Rates	PSD Applicability Determination
	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)		
NOx	91.85	0.92	65.80	0	414.06	0	-255.5	40	No
SO2	13.83	0.10	-70.92	0	564.63	0	-621.6	40	No
TSP	68.74	0.17	-8.49	13.51	68.01	5.79	0.2	25	No
PM10	68.74	0.68	-0.52	1.35	127.87	2.54	-60.1	15	No
PM2.5	68.74	0.68	-1.55	0.14	117.57	2.54	-52.1	10	No
CO	83.08	3.44	85.65	0	37.41	0	134.8	100	Yes
VOC	29.11	0.14	5.10	0	17.29	0	17.1	n/a	n/a
CO2	1,530,936	10,776	101,879	0	774,267	0	869,324	75,000	Yes
H2SO4	12.51	0.0044	-2.36	0	39.93	0	-29.8	7	No

Notes

(1) Preliminary net emissions increase analysis and comparison to significant net emission rates
- Past actual NOx, SO2, and CO2 emissions and heat input (MM Btu/hr) for Units 1, 2 & 3 based on Clean Air Markets Acid Rain database;
- Past actual NOx, SO2, and TSP emissions for Units 1 & 2 discounted to ACO Performance Standards
- PM10, PM2.5, CO, and VOC emissions are based on 2008-2009 emission statements.

(2) Potential Emissions Basis:
3322 hr/yr CCCT operation with duct firing (plus 878 hr/yr shutdown-downtime-hot startup)
3003 hr/yr CCCT operation without duct firing (plus 1557 hr/yr shutdown-down-warm/cold startup)
2436 hr/yr CCCT shutdown-downtime-startup (170 hot startups, 20 warm startups, 10 cold startups. 200 shutdowns)

(3) Potential Emissions based on 91.6 MM Btu/hr and 2000 hr/yr

(4) Difference between projected Unit 3 actual emissions (equivalent to 1200 hr/yr gas fired at 100% load) and past actual emissions (2008-2009 average)
- Unit 3 past actual NOx emissions discounted to 2.0 lb/MW-hr per NJ Subchapter 19 (effective 5-1-2015 for No. 6 fuel oil fired boilers)
- Unit 3 projected NOx based on 1.0 lb/MW-hr (effective 5-1-2015 for gas-fired boilers)
- Unit 3 past actual SO2 emissions discounted based on fuel sulfur content of 5000 ppmw (effective 7-1-2014 for No. 6 fuel oil)

(5) Difference between projected actual emissions (based on Unit 3 operating 1200 hr/yr at 100% load) and past actual emissions (2008-2009 average)

(6) Past actual emissions based on average of 2008-2009 emissions reported to Acid Rain Program or in annual emission statement
Units 1 & 2 NOx emissions discounted to 0.11 lb/MM Btu and based on heat input from Acid Rain Program database
Units 1 & 2 SO2 emissions discounted to 0.15 lb/MM Btu and based on heat input from Acid Rain Program database
Units 1 & 2 TSP emissions discounted to 0.03 lb/MM Btu and based on heat input from Acid Rain Program database
Units 1 & 2 PM10 emissions discounted to ACO performance standard (0.03 lb/MM Btu) for filterable PM plus condensable PM unless actual emissions were less. Unit 3 NOx and SO2 discounted per NOx RACT (N.J.A.C 7:27-19) and fuel sulfur restrictions (N.J.A.C 7:27-9)

(7) Past actual emissions based on average of 2008-2009 emissions reported in annual emission statement

(8) Net Increase (hybrid approach) = $IA_{CCCT} + IA_{AuxBlr} + IA_{U3} + IA_{U8} - DC_{Units1\&2} - DC_{Unit7}$

where: IA = Increase in allowable emissions for new retrofit emission units (CCCT and auxiliary boiler);
NI = net increase for modified units (Unit 3 and Unit 8); and
DC = decrease, creditable emission reductions for retired units (Unit 1, Unit 2, and Unit 7).

(9) PSD rules allow a 5-year lookback to determine past actual emissions.
B.L. England Station is an existing major source for PSD interpretation.

TABLE 4
NONATTAINMENT NSR NETTING ANALYSIS

Emissions Netting for NNSR - Gas Only with Startup/Shutdown - Using 2010-2011 Past Actual Emissions[1]									
	New CCCT Potential Emissions[2]	New Aux Boiler Potential Emissions[3]	Unit 3 Boiler Net Emissions Change[4]	Unit 8 Cool Tower Net Emissions Change[5]	Units 1 & 2 Boilers Past Actual Emissions[6]	Unit 7 Fuel Handling Past Actual Emissions[7]	Total Net Emissions Increase[8]	New Source Review[9]	
	IA_1-CCCT	IA_2-AB	IA_3-U3	IA_4-U8	DC_1-1,2	DC_2-7	$NI = IA_{1-4} + DC_{1-2}$	NNSR Significant Net Emission Rates	NNSR Applicability Determination
Pollutant	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)		
NOx	91.85	0.92	74.30	0	245.91	0	-78.84	25	No
SO2	13.83	0.10	-47.99	0	335.33	0	-369.38	n/a	n/a
TSP	68.74	0.17	-6.14	14.14	61.02	3.31	12.60	n/a	n/a
PM10	68.74	0.68	1.60	1.41	145.37	1.46	-74.39	n/a	n/a
PM2.5	68.74	0.68	0.97	0.14	140.15	1.46	-71.07	n/a	n/a
CO	83.08	3.44	83.99	0	13.97	0	156.53	n/a	n/a
VOC	29.11	0.14	5.33	0	9.85	0	24.72	25	No

Notes

(1) Preliminary net emissions increase analysis and comparison to significant net emission rates
- Past actual NOx, SO2, and CO2 emissions and heat input (MM Btu/hr) for Units 1, 2 & 3 based on Clean Air Markets Acid Rain database;
- Past actual NOx, SO2, and TSP emissions for Units 1 & 2 discounted to ACO Performance Standards
- PM10, PM2.5, CO, and VOC emissions are based on 2010-2011 emission statements.

(2) Potential Emissions Basis: 3322 hr/yr CCCT operation with duct firing (plus 878 hr/yr shutdown-downtime-hot startup)
3003 hr/yr CCCT operation without duct firing (plus 1557 hr/yr shutdown-down-warm/cold startup)
2436 hr/yr CCCT shutdown-downtime-startup (170 hot startups, 20 warm startups, 10 cold startups. 200 shutdowns)

(3) Potential Emissions based on 91.6 MM Btu/hr and 2000 hr/yr

(4) Difference between projected Unit 3 actual emissions (equivalent to 1200 hr/yr gas fired at 100% load) and past actual emissions (2010-2011 average)
- Unit 3 past actual NOx emissions discounted to 2.0 lb/MW-hr per NJ Subchapter 19 (effective 5-1-2015 for No. 6 fuel oil fired boilers)
- Unit 3 projected NOx based on 1.0 lb/MW-hr (effective 5-1-2015 for gas-fired boilers)
- Unit 3 past actual SO2 emissions discounted based on fuel sulfur content of 5000 ppmw (effective 7-1-2014 for No. 6 fuel oil)

(5) Difference between projected actual emissions (based on Unit 3 operating 1200 hr/yr at 100% load) and past actual emissions (2010-2011 average)

(6) Past actual emissions based on average of 2010-2011 emissions reported to Acid Rain Program or in annual emission statement
Units 1 & 2 NOx emissions discounted to 0.11 lb/MM Btu and based on heat input from Acid Rain Program database Units 1 & 2 SO2 emissions discounted to 0.15 lb/MM Btu and based on heat input from Acid Rain Program database Units 1 & 2 TSP emissions discounted to 0.03 lb/MM Btu and based on heat input from Acid Rain Program database
Units 1 & 2 PM10 emissions discounted to ACO performance standard (0.03 lb/MM Btu) for filterable PM plus condensable PM unless actual emissions were less. Unit 3 NOx and SO2 discounted per NOx RACT (N.J.A.C 7:27-19) and fuel sulfur restrictions (N.J.A.C 7:27-9)

(7) Past actual emissions based on reported 2010 emissions and estimated 2011 emissions.

(8) Net Increase (hybrid approach) = $I_{CCCT} + IA_{AuxBlr} + IA_{U3} + IA_{U8} - DC_{Units1\&2} - DC_{Unit7}$

where: IA = Increase in allowable emissions for new emission units (CCCT and auxiliary boiler);
NI = net increase for modified units (Unit 3 and Unit 8); and
DC = decrease, creditable emission reductions for retired units (Unit 1, Unit 2, and Unit 7).

(9) NNSR (per NJ Subchapter 18) allows 5-year lookback if two recent years are not representative.
B.L. England Station is an existing major source for NNSR interpretation

C. AIR POLLUTION CONTROL TECHNOLOGIES

The Project is subject to federal PSD (40 CFR 52.21) requirements including the evaluation of BACT for each PSD-affected pollutant (CO and GHGs). BACT must be applied to control emissions to the maximum degree for each regulated pollutant taking into account technical feasibility, energy, economics, environmental factors and other costs.

The Project is not subject to N.J.A.C.7:27-18 emission offsets and Lowest Achievable Emission Rate (LAER) requirements, since the net emission increase for each nonattainment pollutant is less than the threshold specified in the rule.

1. Nitrogen Oxide (NO_x) Control Technologies

a. Description of NOx Control Technologies

NOx Control Technologies for Combustion Turbine and Utility Boiler (Unit No. 3)

The two major ways in which NO_x is formed in the combustion process are known as fuel NO_x formation and thermal NO_x formation. Fuel NO_x is formed when nitrogen and nitrogen compounds present in the fuel combine with oxygen present in the combustion zone to form NO_x. Thermal NO_x is formed when nitrogen from the air in the combustion zone combines with oxygen in the combustion zone at high temperature. The rate of formation is proportional to temperature in the combustion chamber.

RCCM evaluated the following technologies for controlling NO_x emissions from the proposed combustion turbine and Unit No. 3.

1. Selective Catalytic Reduction System (SCR)

Selective catalytic reduction system (SCR) is a process in which ammonia is injected directly into the flue gas, and the mixture is then passed over a catalyst to react with NO_x, converting the NO_x and ammonia to nitrogen and water. Insertion of a catalyst into the gas path of the HRSG allows this reaction to take place at a temperature within the operating range of the HRSG.

2. Selective Non-Catalytic Reduction (SNCR)

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

3. **Dry Low-NOx Combustors (gas turbine) and Low-NOx Burners (Unit No. 3)**

Dry Low-NO_x (DLN, lean pre-mix) combustors and low-NOx burners (LNB), stage fuel combustion, lowering flame temperatures thus reduce the amount of thermal NO_x formation without the use of diluents such as steam or water.

4. **Lean Burn Combustion (gas turbine)**

Typical gas turbines are designed to operate at a nearly stoichiometric ratio of fuel and in the combustion zone, with additional air introduced downstream. The combustion zone is the point where the highest combustion temperature and quickest combustion reactions (including NO_x formation) occur. Fuel-to-air ratios below stoichiometric are referred to as fuel-lean mixtures (i.e., excess air in the combustion chamber). The rate of NO_x production falls off dramatically as the flame temperature decreases.

Thus, very lean, dry combustors can be used to control emissions by reducing thermal NO_x formation within the combustion chamber. The lean combustors typically are two-staged premixed combustors designed for use with natural gas fuel. The first stage serves to thoroughly mix the fuel and air and to deliver a uniform, lean, unburned fuel-air mixture to the second stage.

5. **Over-fired Air (Unit No. 3)**

Over-fired air (OFA) is a NO_x reduction technique for boilers in which a controlled portion of the combustion air flow is diverted from the burners (reducing NO_x emissions in a fuel rich primary combustion zone) and re-introduced through over-fire ports above the burners.

6. **Flue Gas Recirculation (Unit No. 3)**

Flue gas recirculation (FGR) involves the recycling of a portion of the boiler flue gas back into the burner windbox for mixing with combustion air prior to introduction to the burner. The recycled flue gas acts as a diluent that suppresses thermal NO_x formation, and it also reduces NO_x by reducing the oxygen concentration in the primary flame zone.

b. Technical Review of Proposed NOx Controls

Proposed NOx Controls for Combustion Turbine and Duct Burner

RCCM has proposed to install a DLN combustion system on the combustion turbine and duct burner, along with SCR as SOTA to achieve an emission limitation of 2.0 ppmvd, corrected to 15% O_2 on natural gas for all normal operations.

The Department has compared the proposed emission limitation with emission limitation of similar sized combustion turbines having SCR and DLN in the RACT/BACT/LAER Clearinghouse (RBLC) and found the emissions to be minimal and approvable as SOTA. SCR has been used on hundreds of gas turbine applications throughout the United States and the world, and SCR is a proven technology for the control of NO_x emissions from gas turbines.

Proposed NOx Controls for Unit No. 3

RCCM has proposed to install LNB and OFA on Unit No. 3. The application of SCR and SNCR was evaluated. A computational fluid dynamics (CFD) modeling study predicted NO_x emission rates with various combinations of combustion controls (LNB, OFA and FGR) and SNCR. Based on the results of this study, LNB and OFA were selected for NO_x control. The CFD study also showed that use of SNCR would increase NOx emissions. SCR was also evaluated and determined to be cost effective (excessive cost for pollutant removal) due to limited (equivalent to 1200 hours per year gas fired at 100% load) of operation and retrofitting requirements. Therefore, the Department has determined that SOTA control of NO_x emissions from Unit No. 3 will be the use of LNB and OFA.

2. VOC Control Technologies

a. Description of Control Technologies

Combustion Control

The emissions of VOC in a combustion process are a result of the incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form carbon dioxide (CO_2) and H_2O. The rate of VOC emissions depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air.

Oxidation Catalyst:

In an Oxidation catalyst, exhaust gases are passed over a catalyst bed where excess air oxidizes the CO to CO_2. CO reduction efficiencies in the range of 75 to 90 percent can be achieved. 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 which may, in turn, react with water and/or ammonia to form sulfuric acid mist and/or ammonia salt and PM_{10} emissions.

b. Technical Review of VOC Controls

VOC Controls for Combustion Turbine and Duct Burner

Along with good combustion practices, RCCM is proposing the installation of an oxidation catalyst for CO control which will also reduce VOC emissions. The oxidation catalyst will reduce VOC emissions to 0.6 ppm without duct firing. The proposed VOC emissions limits when burning natural gas are 1.5 ppmvd corrected to 15% O_2 at 100% load with supplemental duct-firing. The Department has searched the RBLC for VOC emission limitations of similar sized combustion turbines and found the proposed VOC emission rate is consistent with the recently approved emissions for similar sized turbines. The Department has found the emissions to be minimal and approvable as SOTA.

VOC Controls for Unit No. 3

Along with good combustion practices, RCCM evaluated the use of an oxidation catalyst to control VOC emissions from Unit No. 3. A RBLC review indicated that oxidation catalysts were typically installed to control CO emissions, and BACT for VOC control of utility-scale boilers has historically been the use of best combustion practices. For Unit No. 3, an oxidation catalyst was determined to not be cost effective (excessive cost for pollutant removal).

Due to retrofit nature of unit no 3 (installed in 1964) and limiting hours of operation of this unit, the Department has determined that SOTA control for VOC emissions from Unit No. 3 will be the use of good combustion practices and Continuous Emissions Monitoring (CEM) for CO as a surrogate monitor. CO and VOC are the byproducts of incomplete combustion, and are directly correlated. Monitoring CO emissions indirectly monitors VOC emissions. Thus, continuous CO monitoring is used as surrogate monitoring for VOC.

3. Carbon Monoxide (CO) Control Technologies

a. Description of Control Technologies

Combustion Control

Carbon Monoxide is usually generated due to the incomplete combustion of fuel. CO emissions are minimized by good combustion practices that oxidize all carbon and hydrogen contained within the fuel to form CO_2 and H_2O. Several factors lead to incomplete combustion, including insufficient O_2 availability, poor air/fuel mixing, cold wall flame quenching, reduced combustion temperature, decreased combustion residence time and load reduction. By controlling the combustion process carefully, CO emissions can be minimized.

Oxidation Catalyst

After combustion control, the only practical control method to reduce CO emissions from combustion of fuel is the use of an oxidation catalyst. Exhaust gases from the combustion equipment are passed over a catalyst bed where excess air oxidizes the CO to CO_2. CO reduction efficiencies in the range of 75 to 90 percent can be achieved, although CO reduction may at times be somewhat less than the design value.

Process Controls

Modern data acquisition and control systems, which optimize combustion performance, also minimize pollutant emissions, including CO, through a combination of operator and software-driven process adjustments and notifications.

b. Technical Review of CO Controls

CO Controls for Combustion Turbine and Duct Burner

RCCM is proposing the use of an oxidation catalyst as BACT for CO emissions along with process control and good combustion practices. The oxidation catalyst system will reduce inlet CO concentrations by 70% or more during all steady-state operating modes. The oxidation catalyst will be located in an optimum temperature region within the HRSG immediately upstream of the SCR ammonia injection grid and downstream of the gas-fired duct burner. The proposed emission limitation when firing natural gas is 2.0 ppmvd corrected to 15% O_2 at 100% load.

The Department has reviewed and found the proposed CO emission limitation of 2.0 ppmvd corrected to 15% O_2 after the application of oxidation catalyst and process controls to be BACT for the combustion turbine with duct burner.

CO Controls for Unit No. 3

Along with good combustion practices, RCCM evaluated the use of an oxidation catalyst to control CO emissions from Unit No. 3. An oxidation catalyst was determined not cost effective (excessive cost for pollutant removal).

Due to the retrofit nature of Unit No 3 (originally installed in 1964) and limiting equivalent hours of operation of this unit, the Department has determined that SOTA control for CO emissions from Unit No. 3 will be the use of good combustion practices and CEM for CO as a surrogate monitor.

CO Controls for Auxiliary Boiler

Although an oxidation catalyst has been used to reduce CO emissions from boilers, it is not considered technically feasible to use it with the auxiliary boiler since the auxiliary boiler is required to supply steam quickly to the combined cycle units during the startup procedure and the oxidation catalyst requires a high flue gas temperature to achieve effective control. A more effective method of reducing emissions, including CO, is by good combustion controls and restricting operation to less than 2000 hrs per year.

4. Control Technologies for Sulfuric Acid Mist

a. Description of Sulfuric Acid Control Technologies

Sulfur dioxide emissions are formed from oxidation of sulfur in the fuel. A fraction of the SO_2 is further oxidized to SO_3, which in turn may react with water vapor to form sulfuric acid mist. The most practical means for controlling SO_2 emissions from combustion equipment is to use low sulfur content fuel like natural gas. The proposed facility will use only natural gas as a fuel.

b. Technical Review of Sulfuric Acid Controls

Sulfuric Acid Controls for Combustion Turbine and Duct Burner

The New Source Performance Standard (NSPS) sulfur content limit for combustion turbines (40 CFR Subpart KKKK) in natural gas is 20 grains sulfur/100 standard cubic feet (scf). RCCM is proposing natural gas, an inherently low sulfur fuel, as the exclusive fuel for the combustion turbine and duct burner. The maximum fuel sulfur limit for natural gas proposed by RCCM is 0.8 grains/100 scf. The maximum is based on a review of historical information. This maximum limit is well below the NSPS limit.

Sulfuric acid mist emissions are minimized by use of low sulfur fuels. H_2SO_4 emissions will be limited to 6.18 lb/hr with duct firing and 5.86 lb/hr without duct firing. The Department has reviewed the proposed sulfuric acid mist emissions and found them to be SOTA.

Sulfuric Acid Controls for Unit No. 3

The use of natural gas in Unit No. 3, as described above, has been determined to be SOTA for sulfuric acid mist emissions.

5. PM/PM_{10}/$PM_{2.5}$ Control Technologies

a. Description of Control Technologies

PM, PM_{10} and $PM_{2.5}$ emissions from the combustion turbine and duct burner may be formed from non-combustible constituents in fuel or combustion air, from products of incomplete combustion, or from the formation of ammonium sulfates due to the conversion of SO_2 to SO_3, which are then available to react with NH_3 and form ammonium sulfate or ammonium bisulfate post combustion.

b. Technical Review of PM /PM_{10}/$PM_{2.5}$ Controls

PM/PM_{10}/$PM_{2.5}$ Controls for Combustion Turbine and Duct Burner

A review of approximately 295 natural gas-fired combined-cycle facilities from the USEPA's RBLC and recently issued air permit lists PM/PM_{10} emission limits ranging from 0.0013 to 0.140 lb/MM Btu. In many instances, the pollutant listed in the RBLC database is TSP or PM. TSP and PM typically only include the filterable portion of particulate matter; therefore, many of these limits cannot be compared to the proposed project. Control technologies, good combustion practice and low-sulfur fuel should be considered the driving factors for proposing SOTA.

Particulate matter is formed from non-combustible constituents in the fuel or combustion air, or from formation of ammonium sulfates post combustion. Add-on controls for PM, PM_{10} or $PM_{2.5}$ is not used for any combustion turbine according to RBLC data. Post-combustion controls, such as baghouses, scrubbers and electrostatic precipitators (ESP), are impractical due to the high pressure drops, the large flue gas volumes and the low concentrations of PM/ PM_{10}/$PM_{2.5}$ present in the exhaust gas.

The combustion of clean burning fuels is the most effective means for controlling PM emissions from combustion equipment. RCCM is proposing exclusive use of natural gas as the fuel for the turbine and duct burner. The proposed emission limit for Unit No.2 for PM/PM_{10}/$PM_{2.5}$ is 16.86 lb/hr without the duct burner. When operating with the duct burner, the proposed emission limit is 20.62 lb/hr. RCCM is proposing a TSP emission limit that is set equal to PM_{10}.

PM/PM$_{10}$/PM$_{2.5}$ Controls for Unit No. 3

The use of natural gas in Unit No. 3, as described above, has been determined to be SOTA for PM/PM$_{10}$/PM$_{2.5}$ emissions in context of switching fuel from fuel oil No. 6 to natural gas and limiting (equivalent to 1200 hours per year gas fired at 100% load) operation.

6. Greenhouse Gasses (GHGs) Control Technologies

The main sources of GHG emissions for the Project are the combustion turbine and duct burner. GHG emissions are also generated from the operation of the auxiliary boiler for limited operation. GHG emissions from Unit No. 3 will be lower on a lb/hr basis and a lb/MWh basis after conversion to natural gas based on the lower GHG production of natural gas fuel.

On June 3, 2010, EPA issued a final rule that "tailors" the applicability provisions of PSD for GHG emissions. Under the tailoring rule, a project that commences construction after July 1, 2011 at an existing major stationary source such as B L England is subject to PSD permitting requirements for GHG emissions if the net GHG emissions increase equals or exceeds 75,000 tpy.

Because B L England is an existing major source and the net GHG emissions increase from the Project will be greater than 75,000 tons/year, the proposed Project is subject to PSD permitting requirements for GHG emissions.

For PSD purposes, GHGs are considered a single air pollutant, carbon dioxide equivalent (CO_2e), which is defined as the aggregate group of the following six gases:

- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)
- Hydro fluorocarbons (HFCs)
- Per fluorocarbons (PFCs)
- Sulfur hexafluoride (SF_6)

a. Description of GHG (CO_2e) Control Technologies:

The major constituent of CO_2e emissions for combustion sources is CO_2, which accounts for over 99% of CO_2e emissions; therefore it is necessary to control CO_2 emissions.

1. Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) is typically viewed as a three-component process that includes capture and compression of CO_2; transport of the captured CO_2 (usually in pipelines); and storage of the CO_2 in geologic formations, such as saline formations, oil and gas reservoirs, and un-mineable coal seams.

The term "CCS" is used to represent all three components of the system: capture/compression, transport, and storage.

CO_2 capture is the separation and capture of CO_2 from the flue gas. This process requires a significant amount of energy and is thus very costly. CO_2 capture technologies (typically applied to coal-fired power generation) can be categorized into the following three approaches:

- **Pre-combustion systems** - designed to separate CO_2 and H_2 in the high-pressure syngas produced at Integrated Gasification Combined Cycle ("IGCC") power plants. The carbon in the syngas is captured before combustion occurs.

- **Post-combustion systems** - designed to separate CO_2 from the flue gas produced by typical fossil fuel combustion (in air). Separating CO_2 from the flue gas is challenging. A high volume of gas must be treated because the CO_2 in the exhaust is dilute (3 – 4% by volume in natural gas-fired systems). Currently, there are several commercially available solvent-based capture processes, and processes employing solvents, solid sorbents, and membranes are at varying stages of development.
- **Oxy-combustion** - Oxy-combustion systems rely on combusting coal or other fuels with relatively pure O_2 diluted with recycled CO_2 or CO_2/steam mixtures. Under these conditions, the primary products of combustion are water and CO_2, with the CO_2 purified by condensing the water.

Once the CO_2 is captured, it must be transported to a storage site. The main method for transporting CO_2 is through a pipeline. However, these pipelines may encounter challenges of their own including cost, regulation, rights-of-way, and public acceptance.

CO_2 storage is the process of injecting the CO_2 into formations below the surface of the earth for long-term sequestration. CO_2 storage projects involve several phases that include: (1) a pre-injection phase that consists of a geologic evaluation of site suitability and modeling to predict how the CO_2 will migrate; (2) an operational phase in which the CO_2 is injected, the well is tested, and the CO_2 plume is tracked; and 3) a post-injection phase of site monitoring and site closure.

EPA guidance states that CCS may be eliminated from consideration if the three CCS components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations. CCS was eliminated as a control option in the CCCT GHG BACT process because it is infeasible to apply such technology to the Project.

The basic reason that CCS is not technically feasible for CCCT is that CCS systems have not been applied to natural gas-fired combined-cycle units. In addition, CCS systems for coal-fired power plants (the focus of current research and development) are not expected to be commercially available until 2030 – which means commercialization of CCS for natural gas-fired combined-cycle plants would not be expected any time before 2030.

In addition to the problems with capturing CO_2 from a natural gas-fired combined-cycle project, many technical feasibility issues revolve specifically around the second and third components of CCS: transport and storage.

Current information from the U.S. Department of Energy (DOE) demonstrates that there are no existing CO_2 pipelines to transport compressed CO_2 from the CCCT Project to CO_2 storage resources, nor is there access to suitable geologic CO_2 storage resources within the project area.

CO_2 pipelines are available for CO_2 for enhanced oil recovery ("EOR") but these pipelines are located in the Southeast and Southwest regions of the U.S. and near the Rocky Mountains. No such pipelines are available in New Jersey to transport the Project's CO_2 to potential storage sites.

Current Department of Energy (DOE) analyses show that there are no viable land-based CO_2 storage resources in New Jersey. According to DOE's *2010 Carbon Sequestration Atlas of the United States and Canada*, the total CO_2 storage resources in New Jersey are "zero". This is because there are no saline formation storage resources, and the un-mineable coal storage resources and oil/gas reservoir storage resources have not been assessed yet by DOE.

Transporting CO_2 from the B L England site to the ocean would be cost prohibitive and, given strong public opposition due to safety concerns, would most likely fail to be licensed.

The logical conclusion from the aspects discussed above is that application of CCS to CO_2 emissions from this unit is not technically feasible.

Additional reasons for rejecting CCS relate to unacceptable energy, economic, and environmental impacts. The DOE recently released a study which presented cost and performance data for advanced natural gas-fired combined-cycle plants with CO_2 capture. The study was restricted to just the first component of CCS (carbon capture) and found that net plant efficiency dropped from 50.2% for the non-capture case to as low as 41.3% for the worst-capture case. The energy penalty results because the CO_2 capture processes use a significant portion of the energy produced from the power plant. In addition, the plant capital costs resulting from the inclusion of CO_2 capture increased anywhere from 82% to 308%.

Other negative impacts and issues relating to CCS include the following.

- Emissions of criteria air pollutants can increase significantly due to the energy penalty of capturing the CO_2.
- Storage resources are generally far from the generating facilities and energy consumers and would thus require the construction of very long pipelines. Besides being costly, these pipelines will be very difficult to license and will be disruptive to the environment during construction.
- There is a lack of legal and regulatory infrastructure (including liability protection) to guide CCS deployment especially in regards to the permanence of CO_2 storage.
- There are also concerns that an earthquake, similar to the 3.9 magnitude earthquake that shook the Northeast U.S. on November 30, 2010, could damage CO_2 pipelines and storage sites.

2. Thermal Efficiency

The design base load net heat rate for the CCCT is 7,434 British thermal units per kilowatt-hour (Btu/kWh, HHV basis) without duct firing at ISO conditions. This heat rate reflects the Project's net output power production.

The appropriate heat rate limit for the permit was determined by applying the following compliance margins to the base heat rate, consistent with other recent GHG BACT applications:

- 3.0% design margin reflecting the possibility that the equipment as actually constructed and installed may not fully achieve the assumptions that went into the design calculations.
- 2.5% degradation margin reflecting combustion turbine efficiency losses due to normal equipment degradation prior to maintenance overhauls.
- 3.0% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

The proposed net heat rate, 7,434 Btu/kWh, is consistent with other recent GHG BACT determinations for the recently permitted facilities in the country, which contain net heat rate limits ranging from 7,605 to 7,730 Btu/kWh for natural gas-fired combustion turbines (operating at 100% load, ISO conditions and without duct firing).

b. Technical Review of GHG Controls

GHG Controls for Combustion Turbine and Duct Burner

To minimize GHG emissions, RCCM proposes to operate the combustion turbine in combined-cycle mode with natural gas as the exclusive fuel, and RCCM proposes a design heat rate limit of 7,434 Btu/kWh (HHV) at base load conditions without duct firing (based on net output).

The Department is also requiring a GHG emission limitation of 916.4 lb CO_2/MWh (gross output) for CCCT based on a 12-operating month rolling average. Compliance with the annual limit will be demonstrated through the use of a CO_2 CEMS and measurements of gross unit output.

In addition to the heat rate limit and lb CO2/MWh emission limits discussed above, the permit will include an annual GHG BACT limit for the CT/HRSG of 1,530,936 tons/year CO_2e based on a rolling 12-month average. Compliance with the annual limit will be demonstrated through the use of a CO_2 CEMS along with fuel usage and emission factors to calculate minor methane and nitrous oxide emissions. The Department has determined that the CCCT satisfies BACT for GHG.

GHG Controls for Auxiliary Boiler

A search of the RBLC for "carbon dioxide" did not yield any results for auxiliary boiler similar to that proposed for the Project. The reduction of GHG emissions from the auxiliary boiler will be achieved by limiting the (equivalent to 1200 hours per year gas fired at 100% full load) operation at and using natural gas. The Department has determined that proposed operating hour and fuel limitations satisfy BACT for GHG.

GHG Controls for Unit No. 3

Similar to the auxiliary boiler, the reduction of GHG emissions from Unit No. 3 will be achieved by limiting the equivalent hours of operation at full load and using natural gas in lieu of fuel oil No.6. The Department has determined that proposed operating limitations satisfy BACT for GHG.

D. APPLICABLE REGULATIONS

1. Prevention of Significant Deterioration (PSD) of Air Quality

The Department has determined that the proposed Project is subject to all applicable requirements of the federal PSD regulations codified at 40 CFR 52.21. The facility threshold for PSD applicability is 100 tons per year of potential emissions of any regulated pollutant, or greater than 100,000 tons per year of potential emissions of GHG for fossil fuel-fired steam electric plants greater than 250 MMBtu/hr heat input. PSD applicability is determined on an individual pollutant basis. Based on the potential annual emissions in Table 3, the Project was determined to be subject to PSD requirements for emissions of CO and GHG (CO_2e).

Air Quality Impact Analyses

In addition to the BACT control technology requirements discussed in Section C above, the Project is required to conduct an air quality impact analyses to show that the Project will be in compliance with the NAAQS, NJAAQS, and PSD Class I and Class II increments and to determine the effect which the Project would have on:

(1) Visibility, soils and vegetation that would occur as a result of the source and general commercial, residential, industrial and other growth associated with the Project,

(2) Impact on air quality projected for the area as a result of general commercial, residential, industrial and other growth associated with it.

Air dispersion modeling shows that there will be no adverse impacts on visibility, soils and vegetation and projected air quality as the result of the Project itself or due to general commercial, residential, industrial and other growth associated with it.

Environmental Justice (EJ) Analyses

The requirement for an EJ analysis originated with the establishment of Executive Order 12898, entitled “Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations” (February 11, 1994). The Order requires federal agencies to consider disproportionate adverse human health and environmental impacts on minority and low-income populations.

Based on the preliminary screening of demographics within two mile radius of the proposed project, no “community of concern” is identified based on income or race that would trigger a federal PSD EJ review. In addition, the anticipated environmental impacts due to the construction and operation of this project to the surrounding community are not expected to affect adversely.

Brigantine Wilderness Area

RCCM has obtained approval from the Federal Land Manager representative that stated the following. "Per the information contained in your letter dated December 6, 2012, visibility impairing pollutants are decreasing as a result of the proposed modifications. Therefore, the Fish and Wildlife Service does not request that any Class I analyses be performed."

2. N.J.A.C. 7:27-18 (Subchapter 18)

Cape May County is nonattainment for ozone (precursors NO_x and VOC). The facility is not subject to subchapter 18 for NO_x and VOC as the net emissions increase at the facility for each of these two ozone precursors is less than 25 tons per year (the threshold for severe ozone nonattainment, which applies to the entire state of New Jersey). The facility is also not subject to this subchapter for CO as it is located in an attainment area for CO.

Air Quality Impact Analysis

Air dispersion modeling for criteria pollutants indicates that the predicted impacts from these pollutants would meet the NAAQS and NJAAQS.

3. Other Regulatory Requirements

a. Federal Regulations

Compliance Determination with Federal $PM_{2.5}$ NSR Requirements

The Project would be located in a current $PM_{2.5}$ attainment area of New Jersey, and hence, is not subject to federal nonattainment NSR requirements for $PM_{2.5}$.

New Source Performance Standards (NSPS)

In addition to PSD regulations codified at 40 CFR 52.21, the Project is subject to the following subparts of NSPS codified at 40 CFR 60:

- Subpart A: General Provisions
- Subpart KKKK, the NSPS for stationary gas turbine.
- Subpart Dc, the NSPS for industrial steam generating units greater than or equal to 10 MM BTU/hr but less than 100 MM BTU/hr (auxiliary boiler)

The emission limitations proposed by the Project as shown in Table 1 (CCCT) and Table 2 (Unit 3) and discussed in Section C satisfy the NSPS requirements.

Unit 3 is an existing boiler for which the rate of emissions of NSPS-regulated pollutants will decrease; therefore, the conversion to natural gas does not trigger NSPS applicability.

Furthermore, the conversion of Unit No. 3 does not trigger the "reconstruction" definition for NSPS applicability.

Acid Rain Program

The Acid Rain Permit is proposed pursuant to the air pollution control permit provisions of Title IV of the federal Clean Air Act, federal rules promulgated at 40 CFR 72, and state regulations promulgated at N.J.A.C. 7:27-22. These rules require facilities operating "affected units" that are subject to the Acid Rain Program to obtain an Acid Rain Permit for those units. Pursuant to Title IV of the Clean Air Act, the United States Environmental Protection Agency (USEPA) has not previously approved sulfur dioxide allowances for the proposed combined-cycle unit (Unit No. 4). Each allowance provides authorization to emit up to one ton of sulfur dioxide during a specified calendar year. In accordance with USEPA's rules, RCCM may sell or purchase allowances on the open market in order to more accurately reflect current operation. The total number of SO_2 allowances required for Unit 4 is 14 tpy. This will be offset with allowances obtained from the shutdown of coal Units 1 and 2 and the conversion of Unit 3 from oil to natural gas. The conversion of Unit No. 3 to natural gas reduces the potential annual SO_2 emissions from this unit to less than 2 tpy.

National Ambient Air Quality Standards

The NAAQS are codified at 40 CFR 50. The air dispersion modeling analysis discussed in Section F, demonstrates Project's compliance with the NAAQS requirements.

Maximum Achievable Control Technology (MACT)

The MACT standards are codified at 40 CFR 63 (National Emission Standards for Hazardous Air Pollutants for Source Categories), and are applicable to sources that emit Hazardous Air Pollutants (HAPs).

The combustion turbine along with duct burner is the source of HAPs. The MACT rules for this source are codified at:

Subpart YYYY:	for Stationary Combustion Turbine,
Subpart UUUUU:	for Electric Utility Steam Generating Units, and
Subpart DDDDD:	for Industrial, Commercial, and Institutional (ICI) Boilers.

Unit No. 4 will be a new source at a major source of HAPs. A source is major for HAPs if the total potential emissions of HAPs from the facility are 25 tons per year or greater, or if the emissions of a single HAP are 10 tpy or greater. Based on potential HAP emissions from the aggregate of sources, the B L England Station will remain major for HAPs after repowering.

The total of all reportable HAPs expected to be emitted from Unit No. 4 (including duct firing) are 24.6 tpy. Formaldehyde would be the single HAP to be emitted from the CCCT with the highest estimated annual emission rate of 6.9 tpy.

Since B L England Station is a major source of HAPs, the CCCT would be subject to any applicable MACT standards at Subpart YYYY. Per 40 CFR 63.6095(d), Subpart YYYY standards for lean pre-mix gas-fired combustion turbines have been stayed; applicants need only comply with the initial notification requirements in 40 CFR 63.6145 until the EPA takes final action and publishes it in the Federal Register.

Per 40 CFR 63.6092, duct-fired HRSGs are considered steam generating units and are not subject to Subpart YYYY. MACT for electric utility steam generating units are specified in Subpart UUUUU; however, units fired only with natural gas are not subject to Subpart UUUUU per 40 CFR 63.9983(b). The HRSG is not an ICI boiler since it will be a component of a system that serves an electric generator of more than 25 MW that produces electricity for sale. Unit No. 3 is an electric utility steam generator that will be fired only with natural gas; it is also not subject to Subpart UUUUU.

Subpart DDDDD applies to ICI boilers located at major sources of HAPs. The auxiliary boiler is natural gas-fired unit (Subpart DDDDD “Gas 1” boiler category) and is therefore not subject to any numeric emission limits under this subpart.

b. ***New Jersey Regulations***

The facility is subject to New Jersey Air Pollution Control Regulations, codified in N.J.A.C. 7:27-1 et seq. for air pollution control, and the NJAAQS. The proposed emission rates in Table 1 and Table 2 are in compliance with New Jersey regulations.

E. TESTING AND MONITORING REQUIREMENTS

The proposed combined-cycle turbine will be required to conduct stack testing for NOx, CO, TSP, PM_{10}, $PM_{2.5}$, and VOC to demonstrate the ability of the facility to operate within the approved emission limitations. Compliance with SO_2 emission limits will be demonstrated by calculations. In addition, Continuous Emission Monitors (CEM) and recorders for NOx, CO, O_2 and CO_2 will be required. The scope of the stack testing and CEMS is detailed in the draft permit.

F. AIR QUALITY IMPACT ANALYSIS

The Department reviewed the ambient air quality impact of the proposed project. Based on the air quality modeling analysis that included both Project modeling and all B L England Station sources, the Department found that air contaminant emissions from the proposed Facility will not exceed Federal or New Jersey Ambient Air Quality Standards or PSD increments. The source's Class I impacts at the Brigantine National Wildlife Refuge will be within allowable EPA Class I increments, and below Class I area Significant Impact Levels (SILs).

The air dispersion modeling and risk assessment summary dated December 21, 2012, is attached.

State of New Jersey

CHRIS CHRISTIE
Governor

KIM GUADAGNO
Lt. Governor

DEPARTMENT of ENVIRONMENTAL PROTECTION

Division of Air Quality
Bureau of Technical Services
Air Quality Evaluation
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BOB MARTIN
Commissioner

ATTACHMENT I

M E M O R A N D U M

TO: Bachir Bouzid, Bureau of Air Permits

FROM: Joel Leon, Bureau of Technical Services

DATE: December 21, 2012

SUBJECT: RC Cape May Holdings LLC's BL England Station Repowering Project
Upper Township, Cape May Township
APC Facility # 73242, BOP 120001

BL England Generating Station (BLE) is currently a 447 megawatt coal fired power plant located on the Great Egg Harbor Bay in Upper Township, Cape May County, New Jersey. It consists of a coal-fired boiler capable of producing 129 MW (Unit 1), a second coal-fired boiler capable of producing 155 MW (Unit 2), and a residual oil-fired boiler capable of producing approximately 155 MW (Unit 3). The Station also has four 2-MW diesel oil-fired reciprocating engines (Emission Unit 5). Units 1 and 2 are subject to a New Jersey Administrative Consent Order (ACO) requiring significant reductions in sulfur dioxide (SO_2), nitrogen oxides (NOx) and particulate matter.

The proposed Repowering Project is as follows:

- the addition of a 275-MW natural gas-fired Siemens STG6-8000H combustion turbine generator system and heat recovery steam generator (HRSG), which will utilize the existing Unit 2 steam turbine generator,

- the conversion of the Unit 3 boiler (Boiler 3) from residual oil to natural gas,

- the retirement of the coal-fired boilers of Units 1 and 2, and

- a new restriction that will allow only two of the four existing 2 MW diesel reciprocating engines to operate simultaneously from 9 am to 4 pm, May to September of each year, and to discharge to a new 55 ft common stack.

When the Repowering Project is completed, the Station will be capable of producing up to 585 MW (275 MW from the CT, 155 MW from the Unit 2 steam turbine generator, 155 MW from the Unit 3 steam turbine generator). This total excludes the four 2 MW diesel-oil fired reciprocating engines.

The potential to emit from the proposed combined-cycle combustion turbine and its auxiliary boiler are as follows: 92.8 tons/yr of NO_x, 86.5 tons/yr of CO, 13.9 tons/yr of SO_2, 29.2 tons/yr of VOC, 69.4 tons/yr of $PM_{2.5}$, 69.4 tons/yr of PM_{10}, 12.5 tons/yr of H_2SO_4, and 1,541,712 tons/yr of greenhouse gases. However, due to the shutdown of the coal boilers and conversion of Unit 3 to natural gas, the project nets out of Subchapter 18 NNSR for all applicable pollutants (NOx and VOC). The project also nets out of PSD for all pollutants except CO and greenhouse gases.

The Bureau of Technical Services (BTS) has completed its review of the submitted air quality dispersion modeling analysis and other relevant supporting documents. BTS concludes:

- The proposed project's maximum predicted impact of each criteria pollutant will be below its applicable Significant Impact Level except for the 1-hour NO_2 impact during hot startup, the 24-hour $PM_{2.5}$ impact, and the 24-hour PM_{10} impact.

- The predicted impact of the proposed project's emissions, when combined with representative background, will not cause or contribute to a violation of a NAAQS or a NJAAQS. In addition to background concentrations, the modeling demonstration of compliance with the 1-hour NO_2, the 24-hour $PM_{2.5}$, and the 24-hour PM_{10} NAAQS included the impact of other NOx and $PM_{2.5}$/PM_{10} sources at the facility and two nearby facility NOx emissions sources.

- The health risks from the proposed facility's air toxics emissions will be negligible.

Compliance was demonstrated based on the assumption that a maximum of two out of the four existing 2 MW engines operating simultaneously, and Boiler 3 operating a maximum of 1,200 hrs/yr. BTS recommends that conditions be placed in the permit to reflect such assumptions.

Attached is the summary of the air quality impact analysis for the proposed repowering project.

cc: Alan Dresser (BTS);
Yiling Zhang (BTS);
Yogesh Doshi (BAP);
Piyush Desai (BAP)

BL England Generating Station
Repowering Project Modeling Analysis

Conclusion

The air quality impact analysis predicts that, except 1-hr NO_2 during hot startup, 24-hour $PM_{2.5}$ and 24-hour PM_{10}, the maximum impact from each criteriON pollutant at each applicable averaging time will be below its applicable Significant Impact Level (SIL). The proposed project will not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS) or a New Jersey Ambient Air Quality Standard (NJAAQS). Health risks from the proposed air toxics emissions will be negligible.

Document Reviewed

BL England Station – Repowering Project Air Quality Evaluation and Modeling Protocol (dated March 2012, revised May 2012 and June 2012)

BL England Station – Repowering Project Air Permit Application – Siemens Combined-Cycle Combustion Turbine Appendix K – Air Quality Depersion Modeling Demonstration (dated August 2012, revised November 2012)

Facility Description

The Repowering Project will add a natural gas-fired Siemens STG6-8000H combustion turbine (CT) generator and a duct-fired heat recovery steam generator (HRSG) to the site as well as other ancillary equipment and systems. The CT and HRSG supplemental firing will burn natural gas only. Steam from the HRSG will feed the existing Unit 2 steam turbine generator and the entire combined-cycle combustion turbine system will be known as Unit 4. A new natural gas-fired auxiliary boiler will supply additional steam to the CT during startup. The new Unit 4 will vent to a 180 ft high CT/HRSG stack. The auxiliary boiler will vent to a new 60 ft stack. The existing Unit 3 boiler will be converted from oil to natural gas and will be restricted to less than 1,200 hours per year of operation. Boiler 3 will continue to exhaust through the existing 475-ft boiler stack which is higher than the calculated Good Engineering Practice height of 385 ft. Operation of the four existing 2-MW reciprocating engines (Emission Unit 5) will be limited such that no more than two unites will operate simultaneously for peaking capacity. The engines will be discharged to a new 55 ft common stack.

When the Repowering Project is completed, the Station's current maximum power production of 447 MW will be increased to 585 MW (275 MW from the CT, 155 MW from the Unit 2 steam turbine generator, 155 MW from the Unit 3 steam turbine generator). This total excludes the four 2 MW diesel-oil fired reciprocating engines.

The project is subject to PSD review for its emissions of CO and greenhouse gases. The project is not subject to nonattainment new source review for any pollutants. Dry low-NOx burner and SCR will be used to control NO_x emissions. A catalytic oxidation system and good combustion practice will be used to control VOC and CO emissions. The new combined-cycle turbine and auxiliary boiler's potential to emit of air pollutants are the following: 92.8 tons/yr of NO_x, 86.5

tons/yr of CO, 13.9 tons/yr of SO_2, 29.2 tons/yr of VOC, 69.4 tons/yr of $PM_{2.5}$, 69.4 tons/yr of PM_{10}, 12.5 tons/yr of H_2SO_4, and 1,541,712 tons/yr of greenhouse gases. The PSD netting calculation accounted for the ACO SO_2, NOx, and particulate emission limits on the existing Units 1 and 2, the conversion of Unit 3 to natural gas, and the increased emissions of particulates from the existing hyperbolic cooling tower. The following change in net emissions (future potential minus past actuals) for PSD were calculated at the facility: -255.5 tons/yr NO_x, 134.8 tons/yr CO, -621.6 tons/yr of SO_2, 17.1 tons/yr, of VOC, -52.1 tons/yr of $PM_{2.5}$, -60.1 tons/yr of PM_{10}, -29.8 tons/yr of H_2SO_4, and 869,324 tons/yr of greenhouse gases.

Facility Location

BLE is located along the Great Egg Harbor Bay in Upper Township, New Jersey, immediately east southeast of the confluence of the Patcong Creek, the Great Egg Harbor River, the Middle River and the Tuckahoe River. The Station is located approximately 5 kilometers (km) west of Ocean City, New Jersey and 27 km south-southwest of the Brigantine Class I Wilderness Area.

Modeling Approach

Air quality standards compliance demonstration was conducted in three steps. The first step is to model all the Repowering Project's proposed emissions to determine if Significant Impact Levels (SIL) are exceeded for each applicable criteria pollutant and each applicable averaging time.

Step 2 modeling will be performed for any criteria pollutant and averaging period if Step 1 predicted an exceedence of the applicable SIL for such pollutants. This is a "net impact" modeling where the proposed Project will be modeled based on its potential to emit as positive input, and BLE equipment that is currently operating but will be retired or converted will be modeled based on its past actual emissions as negative input.

If an exceedence of SIL is predicted by Step 2 net impact modeling, Step 3 multisource modeling needs to be conducted. BTS will provide BLE emission source information from nearby facilities when needed.

Modeling Methodology

AERMOD model (version 12060) was used in the modeling with regulatory default options. The area surrounding BLE was determined to be rural. Modeling was performed with BTS pre-processed 1-minute ASOS meteorological data for the period of 2005 to 2009 from the Atlantic City Airport. The concurrent upper air data was from Brookhaven, NY.

The receptor grid consists of 7,849 receptors ranging from dense grid to coarse grid. The receptor spacing is 100 m out to 4 km from the facility, 250 m from 4 km to 10 km, and 500 m from 10 km to 20 km. The receptor heights were developed from the 7.5-minute USGS DEM data set. To assess impact on the Brigantine Wilderness Class I area, receptor locations established by the Federal Land Manager were used.

The existing Boiler 3's actual stack height is 475 ft, and the GEP stack height was calculated by the Applicant to be 385 feet. To be conservative, the 385 ft GEP stack height was used when modeling the project's future impact, and the 475 ft actual stack height was used when modeling the emission reductions (negative emissions) from the Units 1 & 2 shut down and Unit 3 fuel conversion.

To be conservative in NO_2 modeling, Tier 1full conversion of NO to NO_2 was assumed for the Project NOx sources, and Tier 2 ratios of 0.75 for annual NO_2 impact and 0.8 for 1-hr NO_2 impact were assumed for NOx emission reduction credit sources.

Background Concentrations

Representative background concentrations used for ambient air quality standards compliance demonstration were provided by BTS to BLE, and are listed in Table 1.

Table 1. Background Concentrations

Pollutant	Monitor Location	Monitor Relative To BLE	Averaging Period	Selected Measurement	Background Concentration (ug/m^3)
NO_2	Millville, NJ	37.1 km WNW	Annual	High	17.0
			1-hr	3-yr avg. 98%	73.6
SO_2	Brigantine, NJ	30.5 km NE	Annual	High	3.1
			24-hr	High 2nd High	22.5
			3-hr	High 2nd High	45.3
			1-hr	3-yr avg. 99%	27.1
PM_{10}	Atlantic City, NJ	19.3 km ENE	24-hr	High 2nd High	60.0
$PM_{2.5}$	Atlantic City, NJ	19.3 km ENE	Annual	3-yr avg.	9.1
			24-hr	3-yr avg. 98%	23.1
CO	Ancora State Hospital, NJ	46.4 km NW	8-hr	High 2nd High	460
			1-hr	High 2nd High	920

Modeling Results

1. Effect of Combustion Turbine Operating Modes and Ambient Temperatures

Air quality impact of a combustion turbine (CT) varies based on the CT's operating load, whether the duct burning (DB) heat-recovery-steam-generator (HRSG) is operating, and the ambient temperature. To be conservative, the operating scenario that produces the worst impact needs to be identified and used in all modeling.

The following four operating scenarios were modeled for each of the three ambient temperatures (-8 ^oF, 54 ^oF, and 100 ^oF):

- CT at 100% load with duct burning (not modeled for -8 ^oF case);
- CT at 100% load without duct burning;
- CT at 75% load without duct burning;
- CT at 60% load without duct burning;

Table 2 lists the CT/HRSG stack parameters and emission rates at different loads and ambient temperatures. Table 3 lists the model predicted impacts at different load and ambient temperatures. Modeling results show that the combination of 100 ^{o}F ambient temperature and CT operating at 100% load with duct burner firing produces the maximum impact. This operating scenario is therefore used in all other modeling involving the combustion turbine.

Table 2. CT/HRSG Stack Parameters and Emission Rates

Determination of Worst-Case Load for Predicted Impacts at 54°F

Emissions Source	Stack Exhaust		Stack Emissions (g/s)			
	Temp. (K)	Velocity (m/s)	NO_x	CO	PM_{10} / $PM_{2.5}$	SO_2
CT (w/ DB) 100% Load	350.71	17.96	2.85	2.17	2.60	0.85
CT (no DB) 100% Load	362.93	18.46	2.45	1.12	1.93	0.74
CT (no DB) 75% Load	359.65	14.74	1.95	0.89	1.64	0.59
CT (no DB) 60% Load	372.58	13.52	1.68	0.77	1.44	0.46

Determination of Worst-Case Load for Predicted Impacts at 100°F

Emissions Source	Stack Exhaust		Stack Emissions (g/s)			
	Temp. (K)	Velocity (m/s)	NO_x	CO	PM_{10} / $PM_{2.5}$	SO_2
CT (w/ DB) 100% Load	345.15	16.06	2.61	1.98	2.40	0.78
CT (no DB) 100% Load	356.04	15.92	2.10	0.96	1.70	0.63
CT (no DB) 75% Load	355.21	13.47	1.71	0.78	1.57	0.52
CT (no DB) 60% Load	371.98	12.61	1.47	0.67	1.39	0.40

Determination of Worst-Case Load for Predicted Impacts at -8°F

Emissions Source	Stack Exhaust		Stack Emissions (g/s)			
	Temperature (K)	Velocity (m/s)	NO_x	CO	PM_{10} / $PM_{2.5}$	SO_2
CT (no DB) 100% Load	353.43	19.24	2.71	1.24	2.12	0.82
CT (no DB) 75% Load	355.26	16.50	2.24	1.02	1.74	0.68
CT (no DB) 60% Load	373.12	14.41	1.91	0.87	1.50	0.52

SO_2 Basis (100% conversion of fuel S to SO_2):
0.0022409 lb SO_2 /MM Btu (0.8 gr S/100 scf natural gas)

Table 3. Combustion Turbine/Heat Recovery Steam Generator Model Impacts

Determination of Worst-Case Load for Predicted Impacts at 54°F

Emissions Source	Modeled Impacts ($\mu g/m^3$)							
	NO_2		CO		$PM_{10}/PM_{2.5}$		SO_2	
	1-hr	Annual	1-hr	8-hr	24-hr	Annual	1-hr	Annual
CT (w/ DB) 100% Load	7.40	0.09	5.96	2.72	2.05	0.08	2.22	0.03
CT (no DB) 100% Load	5.11	0.06	2.56	1.15	1.38	0.05	1.55	0.02
CT (no DB) 75% Load	5.52	0.07	2.62	1.24	1.56	0.06	1.67	0.02
CT (no DB) 60% Load	4.35	0.06	2.08	1.10	1.42	0.05	1.19	0.02

Determination of Worst-Case Load for Predicted Impacts at 100°F

Emissions Source	Modeled Impacts ($\mu g/m^3$)							
	NO_2		CO		$PM_{10}/PM_{2.5}$		SO_2	
	1-hr	Annual	1-hr	8-hr	24-hr	Annual	1-hr	Annual
CT (w/ DB) 100% Load	8.44	0.10	6.74	3.20	2.23	0.10	2.52	0.03
CT (no DB) 100% Load	5.74	0.07	2.75	1.28	1.53	0.06	1.73	0.02
CT (no DB) 75% Load	5.55	0.07	2.66	1.30	1.64	0.06	1.68	0.02
CT (no DB) 60% Load	4.14	0.05	1.95	1.04	1.45	0.05	1.13	0.01

Determination of Worst-Case Load for Predicted Impacts at -8°F

Emissions Source	Modeled Impacts ($\mu g/m^3$)							
	NO_2		CO		$PM_{10}/PM_{2.5}$		SO_2	
	1-hr	Annual	1-hr	8-hr	24-hr	Annual	1-hr	Annual
CT (no DB) 100% Load	6.15	0.08	3.07	1.33	1.51	0.06	1.86	0.02
CT (no DB) 75% Load	5.96	0.07	2.87	1.32	1.50	0.06	1.80	0.02
CT (no DB) 60% Load	4.59	0.06	2.22	1.17	1.40	0.05	1.25	0.02

2. Results of Repowering Project Alone Modeling

The impact of the Repowering Project was modeled to determine if applicable Significant Impact Levels would be exceeded. Equipment modeled for this analysis included the worst case CT/HRSG operation as determined previously (100% load with duct burning at ambient temperature of 100 ^{o}F, auxiliary boiler, Boiler 3 at 155 MW (full load) or 50 MW (partial load). Table 4 lists stack parameters and emission rates of these emission sources.

Table 4. Stack Parameters and Emission Rates of Repowering Project Emission Sources

	CT 100% Load w/DB @100 ^{o}F	**Auxiliary Boiler**	**Boiler 3 155 MW**	**Boiler 3 50 MW**
UTM X (m)	531,441.3	531,407.0	531,562.0	531,562.0
UTM Y (m)	4,348,963.4	4,348,954.9	4,348,862.0	4,348,862.0
Stack Height (ft)	180	60	385	385
Stack Diameter (ft)	22	3.25	13.58	13.58
Exit Velocity (m/s)	16.06	17.47	20.66	6.66
Exit Temperature (^{o}k)	345.15	427.59	329	329
NO_x Emission Rate (lb/hr)	20.71	0.92	152.38	49.15
SO_2 Emission Rate (lb/hr)	6.19	0.21	4.05	1.29
PM_{10}/$PM_{2.5}$ Emission Rate (lb/hr)	19.05	0.68	13.33	4.31
CO Emission Rate (lb/hr)	15.71	3.44	147.62	47.62

Model predicted maximum impacts of the Repowering Project are compared with applicable Class II SILs. Results are listed in Table 5. Results indicate that, for the Repowering Project, the maximum modeled impacts of 1-hr NO_2, 24-hr $PM_{2.5}$ and 24-hr PM_{10} all exceed the respective significant impact levels. Further modeling, taking into account of emissions reductions from shutdowns and fuel conversion, is therefore needed to assess impacts.

Table 5. Comparison of Repowering Project Impact with Class II SILs

Pollutant	Averaging Period	Maximum Predicted Impact(1) (ug/m^3)	Class II SIL (ug/m^3)	Percent Of SIL (%)	Exceedance?
CO	1-hour	85.10	2000	4.3	No
	8-hour	36.91	500	7.4	No
NO_2(2)	1-hour	**26.11**	10	261.1	Yes
	Annual(5)	0.93	1	93.4	No
PM_{10}	24-hour	**5.10**	5	102.0	Yes
	Annual(5)	0.16	1	16.1	No
$PM_{2.5}$(3)	24-hour	**4.34**	1.2	361.7	Yes
	Annual(5)	0.16	0.3	53.7	No
SO_2(4)	1-hour	4.22	7.8	54.1	No
	3-hour	4.38	25	17.5	No
	24-hour	1.54	5	30.8	No
	Annual(5)	0.21	1	20.9	No

(1) Maximum impacts for Boiler 3 are associated with full load.
(2) NO_2 impact assumed 100% conversion of NO to NO_2. 1-hr NO_2 impact is the highest of the 5-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor. Annual impact is the maximum predicted impact.
(3) 24-hour $PM_{2.5}$ impact is the highest of the 5-year averages of maximum 24-hour averages at each receptor. Annual impact is the maximum predicted impact.
(4) 1-hour SO_2 impact is the highest of the 5-year averages of the maximum modeled 1-hour SO_2 concentrations predicted each year at each receptor. Impacts are based on fuel with 0.8 gr/100 scf sulfur content.
(5) Annual emission rate and operating parameters for full CT/HRSG load including duct firing at 54°F.

3. Results of Net Impact Modeling

Upon commercial operation of the Repowering Project, the coal fired Unit 1 will be retired, Unit 2 coal boiler will be shut down, and Unit 3 Boiler will be converted from oil firing to gas firing. This will result significant emissions reductions. Net impact from potential emissions of the Repowering Project minus actual impact from the shut-down and fuel conversion was then modeled. To be conservative, Boiler 3 stack height used in the modeling was 475 ft for fuel conversion credit and 385 ft (GEP height) for the Repowering Project. The NO to NO_2 ratio used in the 1-hr NO_2 modeling was 100% for the Repowering Project and adjusted down to 80% for the emission reduction credit.

Based on operations during 2008-2009 (years used in the PSD netting), BTS determined that only 2 operating scenarios could be used to calculate past actual emissions for modeling net impacts: Unit 2 alone, and Units 1 & 2 operating concurrently. Unit 3 concurrent operation with

Units 1 and 2 in 2008-2009 (72 hours) was considered too low to be included. Table 6 lists the stack parameters and emission rates used in the net impact modeling. Modeling results listed in Table 7 show that particulate emissions reductions did not result in lower $PM_{2.5}$ and PM_{10} impacts. This is because the highest impact contributor is the 60 ft auxiliary boiler and the credit sources were modeled at 475 ft. The two impact plumes did not sufficiently overlap. The modeled net impact still exceeded the SILs of 1-hr NO_2, 24-hr PM_{10} and 24-hr $PM_{2.5}$. Therefore, multisource modeling needs to be conducted for these pollutants and averaging times.

Table 6. Stack Parameters and Emission Rates in Net Impact Modeling [a]

	Units 1 & 2 Existing Configuration (Combined)	Unit 2 Existing Configuration (Alone)
UTM X (m)	531,562.0	531,562.0
UTM Y (m)	4,348,862.0	4,348,862.0
Stack Height (ft)	475	475
Stack Diameter (ft)	21.22	14.99
Exit Velocity (m/s)	16.06	17.18
Exit Temperature (^{o}k)	370.21	327.22
NO_2 Emission Rate (lb/hr)	-333.82	-192.01
SO_2 Emission Rate (lb/hr)	-686.41	-400.01
PM_{10}/$PM_{2.5}$ Emission Rate (lb/hr)	-210.50	-71.51

a. Hourly emission rates calculated assume ACO lb/MM Btu limits and the 95 percentile of the 2008-2009 hourly heat input (Unit 1 = 1,182 MM Btu/hr and Unit 2 = 1,600 MM Btu/hr)

Table 7. Net Impact Results – Repowering Project Minus Units 1 & 2

Emissions Scenario	Sources in Group	1-hr NO_2 (1) (ug/m^3)		24-hr $PM_{2.5}$ (2)(4) (ug/m^3)		24-hr PM_{10} (3)(4) (ug/m^3)	
		Impact	SIL	Impact	SIL	Impact	SIL
Project Only (Full Load) - Boiler 2	Auxiliary Boiler Boiler 3 at Full Load CT (w/ DB) 100% Load at 100°F Boiler 2	**18.83**	10	**4.34**	1.2	**5.10**	5
Project Only (Full Load) - Boilers 1 & 2	Auxiliary Boiler Boiler 3 at Full Load CT (w/ DB) 100% Load at 100°F Boilers 1 & 2	**23.57**	10	**4.34**	1.2	**5.10**	5
Project Only (50 MW) - Boiler 2	Auxiliary Boiler Boiler 3 at 50 MW CT (w/ DB) 100% Load at 100°F Boiler 2	**18.83**	10	**4.34**	1.2	**5.10**	5
Project Only (50 MW) - Boilers 1 & 2	Auxiliary Boiler Boiler 3 at 50 MW CT (w/ DB) 100% Load at 100°F Boilers 1 & 2	**18.83**	10	**4.34**	1.2	**5.10**	5

(1) 100% of $NO_x = NO_2$ for the Project and 80% of $NO_x = NO_2$ for Boilers 1 & 2 credit. Impact is the highest of 5-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor.

(2) Impact is the highest of 5-year averages of maximum 24-hour averages each year at each receptor.

(3) Maximum predicted impact of years 2005 - 2009.

(4) Auxiliary boiler alone produces the highest predicted $PM_{2.5}/PM_{10}$ impacts.

4. Turbine Startup (SU) and Shutdown (SD) Impacts

Combustion turbine startup may produce higher impacts than that of normal operation because the emission control device may not be operating at the optimal condition, and exhaust exit temperature and velocity may be lower than that of normal operation. Therefore, the short-term impact of 1-hr NO_2 as well as 1-hr and 8-hr CO during startup and shutdown need to be evaluated. Based on the applicant projected frequency of cold start (10 times per year), warm start (20 times per year), hot start (170 times per year), and shutdown (200 times per year), BTS informed BLE to only model hot startup and shutdown for 1-hr NO_2 impact and cold startup for CO impact. During startup, the auxiliary boiler will be operating, and Boiler 3 may also be operating at full load (155 MW) or partial load (50 MW). The impacts of different SU/SD scenarios were modeled. Table 8 lists stack parameters and emission rates used in the SU/SD impact modeling. Table 9 lists modeling results in comparison with the applicable NAAQS. Results demonstrate that, during startup/shutdown, NAAQS will not be violated.

Table 8. Stack Parameters and Emission Rates of CT Startup/Shutdown

Emission Sources	Stack Parameters						Emission Rate	
	Location - UTM		Stack Height	Exit Diameter	Exit Temperature	Exit Velocity	NO_x	CO
	X (m)	Y (m)	(ft)	(ft)	(^oF)	(m/s)	(lb/hr)	(lb/hr)
Auxiliary Boiler	531,407.0	4,348,954.9	60	3.25	310.0	17.47	0.92	3.44
Boiler 3 at Full Load	531,562.0	4,348,862.0	385	13.58	132.5	20.66	152.38	147.62
Boiler 3 at 50 MW Load	531,562.0	4,348,862.0	385	13.58	132.5	6.66	49.15	47.62
CT (Cold)	531,441.3	4,348,963.4	180	22.0	179.4	11.46	N/M(1)	542.81
CT (Hot)	531,441.3	4,348,963.4	180	22.0	185.5	8.74	154.70	N/M(1)
CT (Shutdown)	531,441.3	4,348,963.4	180	22.0	179.7	13.47	56.10	125.50

(1) N/M: Not modeled per BTS guidance due to infrequent occurrence of event.

Table 9. CT Startup/Shutdown Impacts Modeling Results

Sources	Pollutant	Averaging Time	Modeled Impacts	Background Concentration	Total Impact	NAAQS Standard
			(ug/m^3)			
CT SU/SD, auxiliary boiler, Boiler 3 (155 MW/50 MW), 2 diesel engines	**CO(1)**	**1-hr**	276.0	92.0	1,196	40,000
		8-hr	136.7	460	597	10,000
CT SU/SD, auxiliary boiler, Boiler 3 (155 MW/50 MW), 2 diesel engines	**NO_2**	**1-hr**	87.9(2)(3)	73.6	161.5	188

(1) Maximum modeled impact occurred during turbine cold startup.
(2) NO_2 is 8th highest (form of the NAAQS); Tier 2 adjustment for NO_2/NO_x ratio.
(3) Maximum modeled impact occurred during turbine hot startup.

5. Results of Multisource Modeling

Results in Table 7 indicate that the maximum impacts of 1-hr NO_2, 24-hr PM_{10} and 24-hr $PM_{2.5}$ all exceeded the respective Significant Impact Levels. Therefore, multisource modeling needs to be conducted for these pollutants and averaging times.

For 1-hr NO_2 multisource modeling, BTS identified the following two nearby major NO_x emission facilities: Atlantic County Utilities (ACU) and Missouri Energy (ME). Stack parameters and NO_x emission rates from these two facilities are listed in Table 10. Multisource modeling also included BLE's four existing diesel generators as well as the Repowering Project's proposed emission sources.

For 24-hr $PM_{2.5}$ and 24-hr PM_{10} multisource modeling, no nearby major $PM_{2.5}$ and PM_{10} emission facilities were identified. In addition to the Repowering Project emission sources, BLE stations existing diesel engines and Unit 3 cooling tower need to be included in the multisource modeling. Stack parameters and emission rates of the diesel generators and the cooling tower are listed in Table 11.

Table 10. Stack Parameters and Emission Rates of Non-BLE Sources

Emissions Source	Stack Parameters						Emission Rate
	Location - UTM		Stack Height	Exit Diameter	Exit Temperature	Exit Velocity	NO_x
	X (m)	Y (m)	(ft)	(ft)	(°F)	(m/s)	(lb/hr)
Missouri CT B	547,884.1	4,357,559.5	32	12.75	675	13.93	125.2
Missouri CT C	547,884.1	4,357,559.5	90	12.75	675	13.93	125.2
Missouri CT D	547,884.1	4,357,559.5	90	12.75	675	13.93	125.2
Atlantic County EG1	547,419.7	4,359,272.9	14	0.67	200	80.13	17.75
Atlantic County EG2	547,419.7	4,359,272.9	19	0.33	200	86.33	7.47
Atlantic County EG3	547,419.7	4,359,272.9	29	0.83	200	99.74	36.26
Atlantic County EG4	547,419.7	4,359,272.9	29	0.83	200	99.74	36.26
Atlantic County Boiler	547,419.7	4,359,272.9	53	3.00	550	4.53	2.29
Atlantic County Incinerator A	547,419.7	4,359,272.9	115	6.50	140	2.16	8.56
Atlantic County Incinerator A	547,419.7	4,359,272.9	112	4.00	140	9.39	20.29

Table 11. Stack Parameters and Emission Rates of BLE Sources

Emissions Source	Stack Parameters					
	Location - UTM		Stack Height	Exit Diameter	Exit Temperature	Exit Velocity
	X (m)	Y (m)	(ft)	(ft)	(^oF)	(m/s)
Two Diesel Engines Combined	531,397.7	4,348.778.7	55	3.29	750	27.4
Unit 3 Cooling Tower	530,962.7	4,348.883.9	208	118.6	90	1.84

	Emission Rate		
Emissions Source	NO_2	PM_{10}	$PM_{2.5}$
	(lb/hr)	(lb/hr)	(lb/hr)
Two Diesel Engines Combined	30.0	14.0	14.0
Unit 3 Cooling Tower	0	2.91	2.91

Results of multisource modeling in comparison with the NAAQS are listed in Table 12. These multisource modeling results demonstrate compliance with all applicable National Ambient Air Quality Standards. It needs to be noted that, diesel engine generator modeling assumed two engines out of the exiting four engines operating simultaneously from 9 am to 4 pm, May to September, and the exhausts are discharged through a new 55 ft common stack. Therefore, the permit should include a condition limiting the diesel generators to a maximum of two engines operating simultaneously from 9 am to 4 pm May through September of each year. Also of note is that of the 87.86 ug/m^3 modeled 1-hr NO_2 concentration listed in Table 12, the vast majority of the impact is caused by the two diesel generators.

Table 12. Results of Multisource Modeled Impacts

Sources	Pollutant	Averaging Period	Modeled Impacts	Background Concentration	Total Impacts	NAAQS Standards
			ug/m^3			
Project plus 2 Diesel Engine Sources	**CO**$^{(1)}$	1-hour	275.98	920	1,196.0	40,000
		8-hour	136.65	460	596.7	10,000
Project, 2 Diesel Engine, and ME/ACU sources	**NO_2**	1-hour$^{(2)}$	87.86	73.6	161.5	188
Project plus 2 Diesel Engine Sources		Annual	1.78	17.0	18.8	100
Project Sources, 2 Diesel Engines, and Cooling Tower	**PM_{10}**	24-hour$^{(3)}$	16.62	60.0	76.6	150
		Annual	1.16	40.9	42.1	50
Project Sources, 2 Diesel Engines, and Cooling Tower	**$PM_{2.5}$**	24-hour$^{(4)}$	11.21	23.1	34.3	35
		Annual	1.09	9.1	10.2	15
Project plus 2 Diesel Engine Sources	**SO_2**	1-hour$^{(5)}$	4.22	27.1	31.3	196
		3-hour	4.38	45.3	49.7	1,300
		24-hour	1.54	22.5	24.0	260
		Annual	0.21	3.1	3.3	60

(1) Maximum modeled impacts occur during cold startup of the combustion turbine.
(2) NO_2 is 8th highest (form of the NAAQS); Tier 2 adjustment for NO_2/NO_x ratio. Emissions reflect normal operation of the combustion turbine.
(3) Maximum predicted PM_{10} impact.
(4) $PM_{2.5}$ is in the form of the NAAQS.
(5) SO_2 is maximum (not form of the NAAQS).
BLE = BL England Station
ME = Missouri Energy
ACU = Atlantic County Utilities
NAAQS = National Ambient Air Quality Standards

6. Class Impact Modeling

The Class I Brigantine Wilderness Area is located approximately 27 km (17 miles) to the north-northeast of the BLE station. Based on BLE's potential emissions, the US Fish and Wildlife Service determined that Class I analyses was not needed. BLE modeled the project net impact on this Class I area (Repowering Project emissions as positive input, and shutdown and fuel conversion emission reduction credits as negative input). Modeled results are presented in Table 13. Results show that the predicted impacts are all below the applicable Class I SIL.

Table 13. Maximum Net Impacts (Project Minus Unit 2) at Class I Area

Pollutant	Averaging Period	Maximum Predicted Net Impact (μg/m³)	Class I Significant Impact Level (SIL) (μg/m³)	Percent of Class I SIL (%)	Exceedance?
CO	1-hour	Not modeled	n/a	n/a	n/a
	8-hour	Not modeled	n/a	n/a	n/a
NO_2 (1)	1-hour	2.658	n/a	n/a	n/a
	Annual	2.60E-3	0.1	2.6	No
PM_{10}	24-hour	0.053	0.3	17.6	No
	Annual	< 0.01	0.2	< 1.0	No
$PM_{2.5}$ (2)	24-hour	0.026	0.07	37.2	No
	Annual	< 0.01	0.06	< 1.0	No
SO_2 (3)	1-hour	0.189	n/a	n/a	n/a
	3-hour	0.078	1.0	7.8	No
	24-hour	0.007	0.2	3.7	No
	Annual	< 0.01	0.1	< 1.0	No

(1) 1-hour NO_2 impact is a Tier 1 impact (100% of NO_x = NO_2) in the form of the SIL (highest of the 5-year averages of the maximum modeled 1-hour NO_2 concentrations predicted each year at each receptor). The annual impact is the maximum predicted Tier 1 impact.

(2) 24-hour $PM_{2.5}$ impact is in the form of the SIL (highest of the 5-year averages of maximum 24-hour averages predicted each year at each receptor). The annual impact is the maximum predicted impact.

(3) 1-hour SO_2 impact is in the form of the SIL (highest of the 5-year averages of the maximum modeled 1-hour SO_2 concentrations predicted each year at each receptor). Impacts are based on fuel with 0.8 gr/100 scf sulfur content.

7. Toxic Air Pollutant Risk Assessment

There are 15 toxic air pollutants with potential to emit over the respective NJDEP Reporting Threshold. Risk assessment was therefore conducted for these pollutants. Potential emissions were estimated based on AP-42 factors and information provided by equipment vendor. Table 14 lists the toxic air pollutants emission rates. Table 15 lists estimated short-term non-cancer risks, which are all below the NJDEP negligible threshold of 1. Table 16 lists the estimated long-term non-cancer risks which are all below the negligible threshold of 1. Table 16 also lists projected cancer risks which are all below the negligible threshold of 1 in a million. Therefore, operation at the BLE station is not expected to cause adverse health impact.

Table 14. Toxic Air Pollutants Emission Rates

Pollutant	Maximum Hourly Emissions		Maximum Annual Emissions	
	Combustion Turbine and Duct Firing HAP Emissions[a] (g/s)	Unit 3 HAP Emissions[b,c] (g/s)	Combustion Turbine and Duct Firing HAP Emissions (g/s)	Unit 3 HAP Emissions (g/s)
Acetaldehyde	0.15419		0.13929	
Acetophenone	0.01570		0.01418	
Acrolein	0.02091		0.01889	
Benzene	0.11704		0.10570	
Formaldehyde	0.22163		0.19890	
Hexane	0.18997	0.47827	0.13995	0.06552
Polycyclic Aromatic Hydrocarbons (PAH)	0.00239		0.00216	
Phenol	0.00923		0.00834	
Propylene Oxide	0.01771		0.01600	
Styrene	0.01816		0.01640	
Toluene	0.05083		0.04586	
Arsenic	0.00010	0.00005	0.00008	0.00001
Cadmium	0.00054	0.00029	0.00046	0.00004
Lead	0.00025	0.00013	0.00021	0.00002
Mercury	0.00013		0.00011	

(a) Maximum hourly emissions from CT are based on the maximum heat input at any temperature; annual combustion turbine emissions are based on the maximum heat input at 54°F
(b) The listed HAPs are only those for which annual emissions exceed the reporting thresholds listed in Table B of N.J.A.C. 7:27-22.
(c) Reportable Unit 3 HAPs include hexane, arsenic, cadmium, and lead. Other HAPs are listed for Unit 3 if they are reportable for the combustion turbine and duct firing.

Table 15. Short-Term Non-Carcinogenic Effect

Pollutant	Maximum Short-Term Concentration (ug/m^3)	Short-Term Ref. Concentration (ug/m^3)	Short-Term Hazard Quotient
Acetaldehyde	6.2E-03	470	**3.2E-02**
Acrolein	8.4E-04	2.5	**2.8E-02**
Arsenic	3.8E-06	0.2	**7.4E-02**
Benzene	4.7E-03	1300	**8.9E-03**
Formaldehyde	8.8E-03	55	**1.4E-02**
Lead	1.0E-05	0.1	**8.5E-03**
Mercury	1.2E-03	0.6	**3.2E-02**
Phenol	8.2E-02	5800	**1.6E-04**
Propylene oxide	7.1E-04	3100	**5.6E-04**
Styrene	7.3E-04	21000	**8.5E-05**
Toluene	4.5E-01	37000	**1.4E-04**

Table16. Long-Term Carcinogenic and Non-Carcinogenic Effect

Pollutant	Maximum Annual Concentration (ug/m^3)	URF (ug/m^3)$^{-1}$	Cancer Risk	Long-Term Ref. Concentration (ug/m^3)	Long-Term Hazard Quotient
Acetaldehyde	6.2E-03	2.2E-06	**1.4E-08**	9	**6.9E-04**
Acetophenone	6.3E-04	---	---	0.02	**3.2E-02**
Acrolein	8.4E-04	---	---	0.02	**4.2E-02**
Arsenic	3.8E-06	4.3E-03	**1.6E-08**	0.015	**2.5E-04**
Benzene	4.7E-03	7.8E-06	**3.7E-08**	30	**1.6E-04**
Benzo(a)pyrene	1.0E-04	1.1E-03	**1.1E-07**	---	---
Cadmium	2.0E-05	4.2E-03	**8.4E-08**	0.02	**1.0E-03**
Formaldehyde	8.8E-03	1.3E-05	**1.1E-07**	9	**9.8E-04**
Hexane (N-)	2.0E+00			700	**2.9E-03**
Lead	1.0E-05	1.2E-05	**1.2E-10**	---	---
Mercury	1.2E-03	---	---	0.3	**3.9E-03**
Phenol	8.2E-02	---	---	200	**4.1E-04**
Propylene oxide	7.1E-04	3.7E-06	**2.6E-09**	30	**2.4E-05**
Styrene	7.3E-04	5.7E-07	**4.2E-10**	1000	**7.3E-07**
Toluene	4.5E-01	---	---	5000	**9.1E-05**