Final Prevention of Significant Deterioration Permit
Fact Sheet

Salem Harbor Redevelopment Project
24 Fort Avenue
Salem, MA

Transmittal No. X254064
Application No. NE-12-022

MassDEP is hereby issuing this Prevention of Significant Deterioration (PSD) Permit Fact Sheet, concurrently with the PSD Permit for the Salem Harbor Redevelopment (SHR) Project. MassDEP's permit decisions are based on the information and analysis provided by the Applicant (Footprint) and MassDEP's own technical expertise. This Fact Sheet documents the information and analysis MassDEP used to support the PSD Permit decisions. It includes a description of the proposed SHR Project, the applicable PSD regulations, and an analysis demonstrating how Footprint complied with all applicable requirements.

I. General Information

Name of Source:	Salem Harbor Redevelopment (SHR) Project
Location:	Salem, Massachusetts
Applicant's Name and Address:	Footprint Power Salem Harbor Development LP 1140 Route 24 East, Suite 303 Bridgewater, NJ 08807
Application Prepared By:	Tetra Tech 160 Federal Street Boston, MA 02110

Prevention of Significant Deterioration/
Comprehensive Plan Application

Transmittal Number:	X254064
Application Number:	NE-12-022

Massachusetts Department of
Environmental Protection (MassDEP)

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On April 11, 2011, MassDEP and the U.S. Environmental Protection Agency Region 1 (EPA) executed an "Agreement for Delegation of the Federal PSD program by EPA to MassDEP" (PSD Delegation Agreement). This PSD Delegation Agreement directs that all Permits issued by MassDEP under the Agreement follow the applicable procedures in 40 CFR 52.21 and 40 CFR Part 124 regarding permit issuance, modification and appeals.

The SHR Project is also subject to the MassDEP Plan Approval and Emission Limitations requirements under 310 CMR 7.02 and Emission Offsets and Nonattainment Review under 310 CMR 7.00: Appendix A (Appendix A).

On December 21, 2012, Footprint Power Salem Harbor Development LP (Footprint) submitted an initial Application to MassDEP requesting a Prevention of Significant Deterioration (PSD) Permit and a 310 Code of Massachusetts Regulations (CMR) 7.02 Major Comprehensive Plan Application

Approval (Plan Approval) for a new 630 megawatt (MW) (692 MW with duct firing) natural gas fired quick start combined cycle electric generating facility (the SHR Project) to be located at the site of the existing Salem Harbor Station. The existing Salem Harbor Station is being shut down. Footprint submitted additional information on April 12, 2013, June 10, 2013, June 18, 2013, August 6, 2013, August 20, 2013, September 4, 2013, and September 9, 2013. MassDEP considered the Application for the Draft PSD Permit to be administratively and technically complete. As such, on September 9, 2013, MassDEP issued a Draft PSD Permit and Draft PSD Fact Sheet for a 30 day public comment period as required by the PSD Delegation Agreement and 40 CFR Part 124 - Procedures for Decision Making. MassDEP subsequently extended the public comment period by three weeks to November 1, 2013.

The Proposed Plan Approval regulates all pollutants affected by the SHR Project, including the pollutants regulated under the PSD Permit, and also implements MassDEP's nonattainment New Source Review (NSR) program regulations at Appendix A. Footprint must ensure that its SHR Project complies with the federal PSD Permit and MassDEP's Plan Approval, as well as other applicable federal and state requirements.

MassDEP held a Public Hearing on October 10, 2013 concerning both the Draft PSD Permit and the Proposed 310 CMR 7.02 Plan Approval. A number of comments were submitted to MassDEP during the hearing and public comment period. On November 1, 2013, the Applicant submitted a comment to MassDEP indicating that it had obtained an additional guarantee from its equipment vendor, General Electric (GE), and that, as a result, the emission limits for Particulate Matter ($PM\backslash PM_{10}\backslash PM_{2.5}$) set forth in the Proposed Plan Approval and the Draft PSD Permit could be reduced by approximately twenty five percent (25%). On December 11, 2013, the Applicant filed a submittal to MassDEP concerning comments that had been submitted by EPA, CLF and HealthLink. Included in the Applicant's submittal was an "Emissions Update and Prevention of Significant Deterioration Best Available Control Technology (BACT)" report dated December 2013. Among other things, the Applicant's December 2013 submittal included revised emissions estimates and guarantees from the equipment vendor (GE) for the combined cycle turbines, as well as a Top Down BACT analysis. On January 10, 2014, the Applicant submitted a letter with supplemental technical information addressing revised start-up and shutdown PM emission estimates. On January 16, 17 and 21, 2014, the Applicant submitted a letter with supplemental technical information addressing revised air quality dispersion modeling results for PM_{10} and $PM_{2.5}$ based upon the reduced PM_{10} and $PM_{2.5}$ emission rates obtained from GE and updated carbon monoxide (CO) and sulfuric acid (H_2SO_4) emission rates for the auxiliary boiler due to the requirement for it to be equipped with an oxidation catalyst control device. These five submittals constitute amendments to the Application, and MassDEP is treating them as such.

In response to the public comments and Applicant's submittals, MassDEP has revised the Draft PSD Fact Sheet and Draft PSD Permit, both of which are now being issued as final actions, subject to appeal to EPA's Environmental Appeals Board (See Section XII on Page 34 of this Fact Sheet).

Based on addressing significant public comments and on all submittals, MassDEP has concluded that Footprint's Application is complete and provides the necessary information showing the SHR Project meets federal PSD regulations. All of Footprint's submitted information is part of the official record for the PSD Permit.

II. Project Location

The proposed plant site is located in Salem, Massachusetts within the existing +/- 65 acre Salem Harbor Station property which is bounded by Fort Avenue and the South Essex Sewerage District wastewater treatment plant to the north; Salem Harbor and Cat Cove to the east and northeast; the Blaney Street Ferry terminal and several mixed-use buildings to the southeast; and by Derby Street and Fort Avenue to the west.

III. Proposed Project

Footprint proposes to construct a nominal 630 megawatt (MW) (692 MW with duct firing) quick-start, combined-cycle natural gas-fired power plant at the proposed plant site. The SHR Project will be configured as two operating units. Each unit will be able to operate independently to respond to dispatch requirements. Most of the SHR Project's equipment will be housed in a building structure that will be approximately 115,000 square feet (sf) in area. The SHR Project will include a variety of power plant equipment including: two gas turbine generators (GTGs); two steam turbine generators (STGs); two heat recovery steam generators (HRSGs) with selective catalytic reduction (SCR) and oxidation catalyst pollution control equipment; generator step-up transformers; two air cooled condensers; an ammonia storage tank; and water tanks. In addition, the SHR Project will include areas within other buildings for administrative and operating staff; warehousing of parts and consumables; and maintenance shops and equipment servicing.

Each operating unit of the proposed SHR Project will be part of a combined-cycle power plant. The first stage in the generation process will be the operation of a GTG set. Thermal energy will be produced in the GTGs through the combustion of natural gas, which will be converted into mechanical energy required to drive the turbine compressor section as well as the generator. Each gas turbine will have the capability to generate in excess of 200 MW under all environmental conditions using solely natural gas. The GTG exhaust gas still contains considerable recoverable heat energy. This heat energy will be recovered in a three pressure level HRSG to produce steam. This steam will be directed to a STG where this heat energy will be converted to electrical energy representing approximately 40 percent (%) of the total energy generated by each unit. Efficiency is enhanced in the cycle by using reheat systems as well as using waste steam to heat feedwater in the HRSG, thereby further improving the overall efficiency of the SHR Project. Once the steam leaves the steam turbine, it is condensed back to water using an air cooled condenser (ACC). This water is then returned to the HRSGs through a system of pumps and control mechanisms. Additional steam may be generated when required by the use of special burners within the HRSGs (duct firing) to increase the electricity produced by the STGs.

Footprint will be using the GE Energy 7F Series 5 Rapid Response Combined Cycle Plant for each main power block**.** Each GE power block can produce approximately 150 MW (300 MW total for the plant) of output within 10 minutes of startup using both operating units together.

Continuous emissions monitoring systems (CEMS) will sample, analyze and record fuel firing rates and nitrogen oxides (NO_x) concentration levels, as well as other "non PSD pollutant" concentrations and the percentage of diluent (either oxygen or carbon dioxide) in the exhaust gas from each of the two HRSG exhaust flues. Exhaust gases will be discharged through a single 230 foot tall stack enclosing two flues (one for each turbine/HRSG), each with a diameter of 20 feet.

Ancillary equipment at the proposed SHR Project will include three additional fuel combustion emission units:

- An 80 million British thermal units per hour (MMBtu/hr) natural gas fired auxiliary boiler equipped with ultra low-NOx burners (Cleaver Brooks "Nebraska" D-type boiler Model No. CBND 80E-300D-65 or equivalent);

- A 750 Kilowatt (KW) (standby rating) emergency generator firing ultra-low sulfur distillate oil containing no more than 0.0015 weight percent sulfur (ULSD) (Cummins Model No. DQFAA Diesel Emergency Generator or equivalent); and

- A 371 brake horsepower (BHP) fire pump engine firing ULSD (Cummins Model No. CFP9E-F50 or equivalent).

Footprint has requested the combined cycle turbines be permitted for year-round operation on natural gas and for the equivalent of 720 hours of operation of natural gas duct firing per rolling 12-month period. The auxiliary boiler will be limited to the equivalent of 6,570 hours of natural gas firing at full (100 percent) load per rolling 12-month period. The emergency diesel engine/generator and the fire pump will each be limited to no more than 300 hours of operation per rolling 12-month period.

IV. PSD Program Applicability and Review

MassDEP administers the PSD program in accordance with the provisions of the April 11, 2011 PSD Delegation Agreement between MassDEP and EPA which states that MassDEP agrees to implement and enforce the federal PSD regulations as found in 40 CFR 52.21.[1]

Review considerations with respect to 310 CMR 7.00: Appendix A Emission Offsets and Nonattainment Review (Appendix A) are not part of the PSD Review Process and are therefore not addressed in this Fact Sheet. MassDEP's evaluation of Emission Offsets and Nonattainment Review for the construction of the proposed SHR Project, as required by Appendix A, is provided in the accompanying CPA Approval.

The PSD regulations at 40 CFR 52.21 require that a major new stationary source of an attainment pollutant, or major modification to an existing major stationary source of an attainment pollutant, undergo a PSD review and that a PSD Permit be granted before commencement of construction.

[1] Section III. Scope of Delegation, Section A., states, "Pursuant to 40 CFR 52.21(u), EPA hereby delegates to MassDEP full responsibility for implementing and enforcing the federal PSD regulations for all sources located in the Commonwealth of Massachusetts, subject to the terms and conditions of this Delegation Agreement."

40 CFR 52.21(b)(1) of the federal PSD regulations defines a "major stationary source" as either (a) any of 28 designated stationary source categories with potential emissions of 100 tons per year (tpy) or more of any regulated attainment pollutant, or (b) any other stationary source with potential emissions of 250 tpy or more of any regulated attainment pollutant. Combined cycle generating facilities like the SHR Project are one of the 28 designated stationary source categories for which 100 tpy of potential emissions qualifies the source as "major."[2]

In addition, once a new stationary source has been determined to be a "major" source, it is subject to PSD review for each regulated attainment pollutant that the source would have the potential to emit in "significant" amounts, which in some cases is lower than the "major" thresholds. 40 CFR 52.21(b)(50)(iv) includes pollutants "subject to regulation" as defined in 40 CFR 52.21(b)(49) as regulated pollutants. Greenhouse Gas (GHG) emissions from new electric generating facilities become a regulated pollutant if the total GHG emissions on a CO_{2e} basis equal or exceed the GHG PSD significant emission rate of 100,000 tpy.

If a new stationary source or new modification is subject to the PSD program, the source must apply for and obtain a PSD Permit that meets regulatory requirements including:

- Best Available Control Technology (BACT) requiring sources to minimize emissions to the greatest extent practical;
- An ambient air quality analysis to ensure all the emission increases do not cause or contribute to a violation of any applicable PSD increments or NAAQS;
- An additional impact analysis to determine direct and indirect effects of the proposed source on industrial growth in the area, soil, vegetation and visibility; and
- Public comment including an opportunity for a public hearing.

V. PSD Applicability

The SHR Project is considered a major source as defined by EPA's PSD program. Potential emissions from the proposed facility are significant for six different PSD pollutants: NO_x, PM, PM_{10}, $PM_{2.5}$, sulfuric acid (H_2SO_4) mist, and GHG. Table 1 shows potential emissions from the proposed new equipment at the site and Table 2 lists total facility potential to emit relative to the PSD major source thresholds and significance level thresholds for PSD regulated pollutants.

[2] "Determining Prevention of Significant Deterioration (PSD) Applicability Thresholds for Gas Turbine Based Facilities," memorandum from Edward J. Lillis, Chief, Permits Branch, EPA, dated February 2, 1993.

Table 1. Facility-Wide Annual Potential Emissions							
Pollutant	**CT Unit 1 (tpy) [1]**	**CT Unit 2 (tpy) [1]**	**Auxiliary Boiler (tpy) [2]**	**Emergency Generator (tpy) [3]**	**Fire Pump (tpy) [3]**	**Auxiliary Cooling Tower (tpy) [4]**	**Facility Total (tpy)**
NO_x	69.9	69.9	2.9	1.7	0.4	0	144.8
CO	42.9	42.9	0.9	1.0	0.3	0	88.0
VOC	13.1	13.1	1.3	0.35	0.12	0	28.0
SO_2	14.2	14.2	0.4	0.0017	0.0006	0	28.8
PM	40.1	40.1	1.3	0.06	0.02	0.43	82.0
PM_{10}	40.1	40.1	1.3	0.06	0.02	0.43	82.0
$PM_{2.5}$	40.1	40.1	1.3	0.06	0.02	0.17	81.8
H_2SO_4 Mist	9.4	9.4	0.24	0.00013	0.00005	0	19.0
Pb	0	0	0.00013	0.000001	0.0000003	0	0.00013
CO_2	1,122,920	1,122,920	31,247	180	66	0	2,277,333
GHG, CO_{2e}	1,124,003	1,124,003	31,277	181	66	0	2,279,530

Table 2. Prevention of Significant Deterioration Regulatory Threshold Evaluation				
Pollutant	**Project Annual Emissions (tpy)**	**PSD Major Source Threshold (tpy)**	**PSD Significant Emission Rate (tpy)**	**PSD Review Applies**
CO	88.0	100	100	No
NO_x	144.8	100	40	Yes
SO_2	28.8	100	40	No
PM	82.0	100	25	Yes
PM_{10}	82.0	100	15	Yes
$PM_{2.5}$	81.8	100	10	Yes
VOC (Ozone precursor)	28.0	100	40	No
Pb	0.00013	100	0.6	No
Fluorides	Negligible	100	3	No
H_2SO_4 Mist	19.0	100	7	Yes
H_2S	none expected	100	10	No
Total Reduced Sulfur (including H_2S)	none expected	100	10	No
Reduced Sulfur Compounds (including H_2S)	none expected	100	10	No
GHG (as CO_{2e})	2,279,530	100,000	100,000	Yes

<u>Table 1 and 2 Notes:</u>

1. Emissions, except CO emissions, for each CT are based on 8,040 hours of natural gas firing per 12 month rolling period at full (base) load (100% load) and 50ºF ambient temperature with no duct burner firing (2,130 MMBtu/hr, HHV) or evaporative cooling, and 720 hours of natural gas firing per 12 month rolling period at peak load (approximately 102% load) and 90ºF ambient temperature with 100% duct burner firing (2,449 MMBtu/hr, HHV CT and duct burner combined) and evaporative cooling, and include start-up and shutdown emissions. Based on new CO emission limit guarantees from the turbine

vendor (GE) that reduced the CO emission limit from 11.0 lb/hr to 8.0 lb/hr under all operating loads, reduction in the number of turbine cold start-ups from 36 to 13, and incorporation of an oxidation catalyst control device to limit CO emissions from the auxiliary boiler from 2.8 lb/hr to 0.28 lb/hr, emissions of CO have been reduced to 88.0 tpy. This CO emission limit can be found in the federally enforceable Plan Approval.

2. Auxiliary boiler emissions are based on 6,570 hours of natural gas firing per 12 month rolling period at 100% load (80 MMBtu/hr, HHV).

3. The emergency diesel generator (EDG) and fire pump (FP) emissions are each based on restricted operation of 300 hours per unit, per 12 month rolling period, including maintenance and periodic readiness testing, while firing ULSD having a sulfur content that does not exceed 0.0015% by weight.

4. The auxiliary cooling tower contributes to particulate emissions only based on 8,760 hours of operation per 12 month rolling period.

Table 1 and 2 Key:

CT = Combustion Turbine
tpy = tons per year
NO_x = Nitrogen Oxides
CO = Carbon Monoxide
VOC = Volatile Organic Compounds
SO_2 = Sulfur Dioxide
PM = Total Particulate Matter
PM_{10} = Particulate Matter less than or equal to 10 microns in diameter
$PM_{2.5}$ = Particulate Matter less than or equal to 2.5 microns in diameter
H_2SO_4 = Sulfuric Acid
Pb = Lead
CO_2 = Carbon Dioxide
GHG = Greenhouse Gases
CO_{2e} = Greenhouse Gases expressed as Carbon Dioxide equivalent and calculated by multiplying each of the six greenhouse gases (Carbon Dioxide, Nitrous Oxide, methane, Hydrofluorocarbons, Perfluorocarbons, Sulfur Hexafluoride) mass amount of emissions, in tons per year, by the gas's associated global warming potential published at Table A-1 of 40 CFR Part 98, Subpart A and summing the six resultant values.
H_2S = Hydrogen Sulfide
ULSD = Ultra Low Sulfur Diesel Fuel Oil containing a maximum of 0.0015 weight percent sulfur
ºF = degrees Fahrenheit
% = percent
MMBtu = million British thermal units
MMBtu/hr = million British thermal units per hour
HHV = higher heating value basis

VI. BACT Analysis

As required by the federal PSD program at 40 CFR 52.21(j)(2) and (3), the SHR Project is required to comply with BACT for the NO_x, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG emissions from the new turbines and other emission units.

BACT is defined as, "an emissions limitation ... based on the maximum degree of reduction for each pollutant subject to regulation under [the Clean Air] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques … for control of such pollutant." 40 CFR 52.21(b)(12); Clean Air Act (CAA) 169(3).

BACT determinations involve an evaluation process known as the "top-down" process. In brief, the "top-down" process involves a ranking of all available control technologies in descending order of control effectiveness. Applicants are required to first examine the most stringent ("top-case") alternative. MassDEP will presume this emission limit represents BACT unless the Applicant can demonstrate that it is not feasible for technical, energy, environmental or economic reasons. If the most stringent control alternative is eliminated, then the Applicant must consider the second best, and so on. The details of this procedure are found in the October 1990 Draft EPA New Source Review Workshop Manual and other EPA policy, guidance, and determinations as applicable, e.g., as indexed in EPA's on-line NSR Policy and Guidance Database at http://www.epa.gov/region7/air/search.htm.

The results of the BACT analyses for the proposed SHR Project are presented below for NO_x, PM, PM_{10}, $PM_{2.5}$, H_2SO_4 mist, and GHG emissions.

Combined Cycle Combustion Turbines

Clean Fuels

For the combined cycle combustion turbines, a major element of the BACT analysis is the use of clean fuels. Footprint has proposed to burn solely natural gas in the combustion turbines. MassDEP agrees that natural gas is the least-emitting fossil fuel available, and therefore represents the most stringent "top" BACT with respect to the selection of turbine fuels. The possible use of ULSD was eliminated by Footprint.

NO_x

In addition to the requirement to apply BACT for NO_x, the SHR Project is also subject to the determination of Lowest Achievable Emission Rate (LAER) for NO_x because potential NO_x emissions exceed the major source threshold of 50 tpy under 310 CMR 7.00: Appendix A, Emission Offsets and Nonattainment Review. Please see the CPA Approval for the LAER analysis.

In order to identify BACT for NO_x for an "F" Class combined cycle combustion turbine facility, Footprint evaluated numerous sources of information. These sources included both state and federal resources of publicly available air permitting information. California, New York, New Jersey, Connecticut, and Massachusetts were the focus for state specific determinations and guidance. Footprint evaluated the following sources of information to determine BACT for NO_x:

- EPA's RACT, BACT, LAER Clearinghouse (RBLC);
- MassDEP's BACT Guidance of June 2011 including Top Case BACT Guidelines for Combustion Sources;
- EPA Region IV's National Combustion Turbine List;

- The California Air Resources Board (CARB) BACT Clearinghouse;

- The California South Coast Air Quality Management District's (SCAQMD) BACT guidelines;

- State environmental program websites;

- New Jersey's State Of The Art (SOTA) Manual for Stationary Combustion Turbines; and

- The California Energy Commission Energy Facilities Siting Board.

In addition to these sources of information, additional publicly available information, such as permits for individual projects not listed in the RBLC or other sources, was also included in the analysis. Please see Footprint's top-down BACT analysis, which is appended hereto as Appendix 1.

Footprint presented the following conclusions:

- A search of EPA's RBLC for the lowest NO_x emission rate for projects approved in the last 10 years for the EPA characterized "Process Type 15.210" (large gas-fired combined cycle combustion turbines) showed that the lowest approved NO_x rate in RBLC is 2.0 part per million volume dry corrected (ppmvdc).

- The EPA Region IV National Combustion Turbine Spreadsheet was examined to identify if any NO_x emission limits more stringent than 2.0 ppmvdc are reported. The only project identified with a NO_x emission limit less than 2.0 ppmvdc is the Sunlaw (CA) Cogeneration Project, which shows "1-2 ppm" for NO_x. However, the RBLC entry for Sunlaw (RBLC ID # CA-0863) confirms the emission level demonstrated in practice for this facility is 2.0 ppm.

- The CARB BACT Clearinghouse had nine records for combined cycle gas turbines greater than 50 MW; the only one more stringent than 2.0 ppmvdc NO_x was the IDC Bellingham Project (in MA), which is shown as having a NO_x limit of 1.5 ppmvdc. This entry contains a note indicating that the limit(s) "are as stringent or more stringent than prior existing SCAQMD BACT for this source category. These limits have not been verified by performance data. These limits were negotiated with the Applicant and are presumably based on vendor guarantees." The IDC Bellingham Project was never built, so the approved NO_x level of 1.5 ppm was never demonstrated in practice. Therefore, IDC Bellingham is not a precedent for NO_x BACT.

- The SCAQMD BACT Clearinghouse has three gas turbine combined-cycle units listed, with two approved at 2.0 ppmvdc and one approved at 2.5 ppmvdc.

- New Jersey's SOTA Manual for combustion turbines specifies a NO_x limit of 2.5 ppmvdc for combustion turbine combined cycle units greater than 150 MMBtu/hr heat input.

- The June 2011 MassDEP BACT guidance for combustion sources identifies 2.0 ppmvdc of NO_x as the "top case" BACT for large gas-fired combined cycle units.

- The two most recent NO_x LAER precedents for similar Massachusetts projects are also 2.0 ppmvdc for gas firing. These are for the Brockton Power Company LLC (Plan Approval No. 4B08015, July 20, 2011) and Pioneer Valley Energy Center (EPA Final PSD Permit No. 052-042-MA15), April 2012).

In summary, Footprint did not identify any BACT precedents for large gas-fired combined cycle turbines where a NO_x emission limit of less than 2.0 ppmvdc has been approved and subsequently demonstrated in practice. Based on this review, MassDEP has determined that 2.0 ppmvdc represents the most stringent technically feasible level of emissions control for NO_x for the SHR Project's proposed combustion turbines.

Footprint has proposed to achieve the BACT NO_x emission limit of 2.0 ppmvdc by using state-of-the-art dry low-NO_x (DLN) combustors in combination with selective catalytic reduction (SCR). DLN combustors are designed to minimize the creation of NO_x in the turbine's combustion chamber. SCR reduces NO_x to nitrogen (N_2) and water (H_2O) in the presence of a catalyst and ammonia.

SCR is placed in the exhaust flue of the combustion turbine. An SCR system is composed of an ammonia storage tank, ammonia (NH_3) forwarding pumps and controls, an injection grid (a system of nozzles that spray NH_3 into the exhaust gas ductwork), a catalyst reactor, and instrumentation and controls. The injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and H_2O in the catalyst reactor.

Several different types of catalysts can be used to accommodate a wide range of flue gas temperatures. Base metal catalysts, typically containing vanadium and/or titanium oxides, are typically used for flue gas exhausts ranging between 450°F and 800°F. Combined cycle combustion turbine projects employ a HRSG to produce steam from the hot exhaust gases exiting the turbine in order to generate additional electricity in a steam turbine. As a result, combined cycle projects proponents can design the HRSG such that a base metal SCR catalyst can be placed within the HRSG under its optimum temperature window to maximize NO_x reduction.

Based on the results of Footprint's NO_x BACT evaluation research, MassDEP accepts Footprint's conclusion that only SCR has been successfully demonstrated in practice to achieve the 2.0 ppmvdc NO_x emission rate that currently represents BACT for large combustion turbines (100 MW or greater).

$\underline{PM/PM_{10}/PM_{2.5}}$

Emissions of particulate matter result from trace quantities of ash (non-combustibles) in the fuel as well as products of incomplete combustion. Footprint proposes to minimize particulate emissions from the proposed SHR Project by utilizing state-of-the-art combustion turbines and good combustion practices to burn natural gas, the lowest ash-content fuel available. Footprint conservatively presumes that all particulate matter (PM) emissions from combustion turbines firing natural gas are less than 2.5

microns in diameter ($PM_{2.5}$). Based on the guarantees supplied by the vendor (GE), Footprint is proposing to achieve emissions of PM, PM_{10}, and $PM_{2.5}$, of: 0.0038 pounds per million British thermal units (lb/MMBtu) at 0ºF to 0.0047 lb/MMBtu at 105 ºF at full load unfired conditions. Footprint presents the PSD BACT limits for $PM/PM_{10}/PM_{2.5}$ for 34 projects approved within the last 5 years. Eighteen of these projects had PM limits that were less stringent than the limits proposed by Footprint and sixteen of these projects had PM limits that were more stringent than the limits proposed by Footprint. Footprint determined that there was no data that show that the PM emissions from any of the projects with more stringent limits could reliably meet these limits on a long term basis. Because Footprint needs the flexibility to run the plant under different load conditions, both with and without duct firing, Footprint requests that MassDEP determine that its proposed emission limits of 0.0071 lbs/MMBtu are BACT. To support this request, MassDEP has evaluated Footprint's request and agrees that Footprint needs the flexibility to operate at different levels including the minimum load level and determined that the proposed limits represent BACT. (See Appendix A, Attachment A-1, Sheets 1, 2 and 3, highlighted text).

Footprint's BACT analysis includes the two most recent state $PM/PM_{10}/PM_{2.5}$ BACT precedents. The Brockton Power Company LLC (Plan Approval No. 4B08015, July 20, 2011) was approved for 0.007 lb/MMBtu for loads down to 60% load. MassDEP concludes that the PM BACT for Brockton and the SHR Project are comparable for SHR Project's CT loads at 75% and greater. Footprint has indicated that the turbine vendor performance levels at minimum emissions compliant CT load without duct firing require a slightly higher lb/MMBtu PM limit. MassDEP has evaluated this request and concludes that the operating flexibility afforded by operating at the minimum load levels warrants the approval of a PM rate of 0.0071 lb/MMBtu at the minimum load conditions.

Pioneer Valley Energy Center (PVEC) (EPA Final PSD Permit No. 052-042-MA15, April 2012) was approved for a $PM/PM_{10}/PM_{2.5}$ emission rate of 0.004 lb/MMBtu for natural gas firing. Footprint points out that PVEC's ability to meet this limit has not been demonstrated in practice since the PVEC Project has not yet been constructed and that it is not consistent with recent test data for the same model turbine. The emission limit for PVEC is based on the MHI 501G turbine, the same turbine used at Mystic Station. Footprint notes that Mystic Station was approved for 0.011 lb/MMBtu, and that the four Mystic Station MHI 501G units had tested PM emissions ranging from 0.005 to 0.010 lb/MMBtu. Footprint contends that the majority of the tested particulate matter was condensable particulates at Mystic. Footprint concludes that it is not reasonable to expect that the MHI 501G unit at PVEC could reliably achieve 0.004 lb/MMBtu in practice. MassDEP has determined that the Footprint position regarding the PVEC emission limit of 0.004 lb/MMBtu has merit. MassDEP concludes that the PM emission rate of 0.0071 lb/MMBtu represents BACT for all operating loads for $PM/PM_{10}/PM_{2.5}$ for the SHR Project's combined cycle turbines.

Sulfuric Acid Mist (H_2SO_4)

Emissions of sulfuric acid mist (H_2SO_4) are generated by the oxidation of sulfur in the fuel. The only means for controlling sulfuric acid mist emissions from the SHR Project is to limit the sulfur content of the fuel. By using pipeline natural gas with a sulfur content of 0.5 grains of sulfur per 100 standard cubic feet, Footprint minimizes its H_2SO_4 emissions and as a result requests an H_2SO_4 emission limit of 0.0010 lb/MMBtu. To support this request, Footprint compiled a list of twenty-two projects that were approved with emission limits for H_2SO_4. Thirteen of these projects had emission limits less stringent than those proposed by Footprint and nine of these projects had emission limits more stringent than those proposed by Footprint. Footprint determined that the more stringent limits were based on unrealistically low assumptions of the oxidation of SO_2 to SO_3 and unrealistically low assumptions on the sulfur content of the fuel. Footprint's BACT analysis included the most recent H_2SO_4 BACT precedent for a similar Massachusetts project. The Pioneer Valley Energy Center (EPA Final PSD Permit No. 052-042-MA15, April 2012) was approved with an H_2SO_4 BACT limit for natural gas firing of 0.0019 lb/MMBtu. The Brockton Power Company LLC Project (Plan Approval No. 4B08015, July 20, 2011) did not include an H_2SO_4 BACT limit. Based on this analysis, MassDEP concludes that Footprint's proposed H_2SO_4 emission limit of 0.0010 lb/MMBtu is BACT for H_2SO_4 for the SHR Project's combined cycle turbines.

Greenhouse Gas Emissions (GHG)

Greenhouse gas emissions for PSD permitting from combustion sources are the aggregate of three pollutants: carbon dioxide, methane, and nitrous oxide. Since each pollutant has a different effect on global warming, PSD applicability is based on a carbon dioxide equivalent (CO_{2e}), determined by multiplying each pollutant by its global warming potential. Like other combustion sources, the main constituent of GHG for a combined cycle turbine is carbon dioxide. For Footprint's proposed combined cycle turbines, their carbon dioxide emissions constitute 99.9% of their GHG emissions on a CO_{2e} basis. Nitrous oxide and methane make up the other 0.1% of the GHG emissions from these combined cycle turbines and their global warming potential is included on a CO_{2e} basis.

The most stringent control technology for control of GHG from a combustion turbine combined cycle unit is by means of carbon capture and storage (CCS). Footprint evaluated the feasibility of CCS based on material published by EPA. CCS is composed of three main components. The first component is the capture or removal of carbon (i.e., CO_2) from the exhaust gas. The second component is transport of the captured CO_2 to a suitable disposal site, and the third component is the actual disposal of CO_2, normally deep underground in geological formations. Footprint pointed out that there is no nearby existing CO_2 pipeline infrastructure (see Figure 4-1, December 11, 2013 Applicant submittal); the nearest CO_2 pipelines to Massachusetts are in northern Michigan and southern Mississippi. Without such infrastructure, MassDEP agrees that CCS is not feasible at this site.

Footprint proposes to use natural gas, the lowest carbon emitting fuel for a fossil fuel project. Footprint chose to install two F Class turbines rather than the slightly more efficient but larger G Class turbines. Footprint selected the F Class turbines because they are compatible with the existing high voltage switchyard and electrical interconnection infrastructure at the site and because they provide greater operational flexibility. Footprint selected air cooling rather than a more efficient wet cooling system to avoid the impingement, entrainment and thermal impacts associated with once through wet cooling and the visible fog plume associated with mechanical draft cooling.

Footprint proposes an initial design limit of 825 pounds CO_{2e} per net Megawatt hour of power delivered to the grid (lb $CO_{2e}/MWhr_{grid}$). Footprint proposes to demonstrate compliance with this value by means of an initial performance test, to be conducted within 180 days of facility startup. This test will be done at CT full (base) 100% load, without duct firing, with the test results corrected to turbine ISO conditions. Footprint also proposes to meet a 365-day rolling average GHG limit of 895 lb $CO_{2e}/MWhr_{grid}$, for the life of the facility, with and without duct firing. This 365 day rolling average limit accounts for operation at varying loads, startup and shutdown, varying temperatures, and in particular unavoidable CT performance degradation between major overhauls and over the life of the facility. Footprint's proposed limits are identical to the approved GHG BACT limits for the Pioneer Valley Energy Center (PVEC, EPA Final PSD Permit No. 052-042-MA15, April 2012).

Footprint notes that the PVEC Project used a CO_{2e} emission factor of 116 lb/MMBtu. The SHR Project CO_{2e} emission factor is 119 lb/MMBtu, of which CO_2 emissions comprise 118.9 lb/MMBtu and the other GHGs comprise 0.1 lb/MMBtu. Footprint claims this makes its proposal to meet the same limits as PVEC actually 2.6% more stringent than PVEC's approved limits. PVEC obtained their GHG emission factor from its turbine vendor. Footprint and GE calculated their GHG emission factor from procedures contained in the Code of Federal Regulations (40 CFR Part 75, Appendix G, and 40 CFR Part 98, Subparts A and C).

MassDEP notes that Footprint's 365 day rolling average is lower than EPA's proposed New Source Performance Standard (NSPS) for natural gas fired combined cycle turbines greater than 850 MMBtu/hr (approximately 100 $MW_{electrical}$) of 1,000 lb CO_2/MWhr [see Federal Register January 8, 2014 - NSPS for GHGs from New Stationary Sources: Electric Utility Generating Units (EGU)].

Footprint asks that MassDEP adopt its proposed limits as BACT. To support that request, Footprint compiled a list of PSD BACT determinations for new combustion combined cycle projects in the past five years. Footprint found no cases in which post combustion controls including carbon capture and sequestration have been used to control the GHG emissions from large natural gas fired combined cycle turbines. Footprint did not identify any currently operating facility that has more stringent limits that: (a) apply under all load conditions, with and without duct firing, and during start up and shut down, and (b) account for the degradation of energy efficiency over time.

Footprint notes that the Plan Approval for the proposed Brockton Power Plant may contain a more stringent GHG emission limit (Plan Approval No. 4B08015, July 20, 2011). The Brockton Project was approved for a rolling 12-month CO_2 (not CO_{2e}) limit of 842 lb/MWhr, a limit more stringent than the 895 lb CO_{2e}/MWhr proposed by Footprint. The basis for the 842 lb CO_2/MWhr limit in the Plan Application for the Brockton Project is stated "to include operation at a variety of loads, ambient temperatures, with and without evaporative cooling, and with and without duct firing, and including starts and stops" (Brockton Power Plan Application at Page 4-30). However, there is no mention of any allowance for heat rate (efficiency) degradation over the life of the project or between major turbine overhauls. Footprint notes that the Brockton Project has not yet been constructed, and the 842 lb CO_2/MWhr value therefore has not been demonstrated in practice. In addition, Footprint notes that the Brockton Project did not specifically undergo a PSD review for GHG BACT.

Footprint also notes that in the Plan Application for the Brockton Project, it is stated that the 842 lb CO_2/MWhr value is based on a CO_2 emission factor of 117 lb/MMBtu. Footprint notes its proposed limit of 895 lb CO_{2e}/$MWhr_{grid}$ is based on a CO_{2e} emission factor of 119 lb/MMBtu. Adjusting the Brockton value of 842 lb CO_2/MWhr by 118.9/117, the Brockton rate based on 118.9 lb CO_2/MMBtu would be 856 lb CO_2/MWhr. In this case, the SHR Project value (895 lb CO_{2e}/$MWhr_{grid}$) is only 4.6% higher than the adjusted Brockton value (856 lb CO_2/MWhr). In addition, the Brockton Project design is based on wet cooling, while the SHR Project will use dry cooling. Projects using dry cooling have higher heat rates (are less efficient) than wet cooled projects, particularly during the summer months.

MassDEP has reviewed the Brockton Plan Approval and has determined that a reasonable allowance for heat rate (efficiency) degradation over the life of the project and between major turbine overhauls, as well as the impact of wet vs. dry cooling, explains the proposed GHG BACT for the SHR Project of 895 lb CO_{2e}/$MWhr_{grid}$ compared to the proposed Brockton limit. Based on Footprint's BACT Analysis including its evaluation of the Brockton Plan Approval, MassDEP concludes that the 365 day rolling average GHG emissions of 895 lb CO_{2e}/$MWhr_{grid}$, which includes a reasonable allowance for the various factors affecting long-term GHG emissions, including performance degradation, represents BACT for GHG emissions. Therefore the SHR Project proposed GHG BACT limits of 825 lb CO_{2e}/$MWhr_{grid}$ (initial design limit) and the 895 lb CO_{2e}/$MWhr_{grid}$ (365 day rolling average) are approved as BACT for GHG.

Startup and Shutdown Emissions

NO_x is the only PSD Pollutant that has higher emissions during start up and shut down than during normal operation of the CTs. Footprint proposes to comply with BACT for startup and shutdown by employing good operating practices (by following the CT manufacturer's recommendations during startup) and by limiting startup time. The combustion turbines will be operated in accordance with manufacturer specifications during startups and shutdowns in order to ensure that emissions are minimized during these short time periods. Additionally, ammonia injection will be initiated as soon as the SCR catalyst reaches its vendor-specified minimum operating temperature and all system parameters are met to minimize NO_x emissions during these periods. The proposed startup and shutdown emission limits for the pollutants subject to PSD review, except GHGs, are presented in Table 3.

Table 3. Turbine Startup and Shutdown Emission Limits (pounds per event)

Pollutant	Startup (duration 45 minutes)	Shutdown (duration 27 minutes)
NO_x	89	10
$PM/PM_{10}/PM_{2.5}$	6.60	3.96
H_2SO_4	1.3	0.2

Table 4 compares the mass emission limits of the PSD subject pollutants for a startup and shutdown hour to a normal CT operation hour without duct firing. The BACT mass emission limit of a normal operation hour with duct firing are higher for these pollutants so the comparison presented in Table 4 represents a worst case scenario. A startup hour consists of 45 minutes in startup mode and 15 minutes at normal operation. A shutdown hour consists of 33 minutes at normal operation and 27 minutes in shutdown mode.

Table 4. Comparison of Normal Operation Hourly Emission Limit to Startup and Shutdown Hourly Emission Limits for Each Turbine (lbs per hour)

Pollutant	Normal Operation Hour	Startup Hour	Shutdown Hour	PSD BACT
NO_x	17.0	93.2	19.4	Since startup and shutdown emissions exceed normal operation, BACT for startup and shutdown NO_x emissions must be established (see Appendix 1)

Table 4. Comparison of Normal Operation Hourly Emission Limit to Startup and Shutdown Hourly Emission Limits for Each Turbine (lbs per hour)				
Pollutant	**Normal Operation Hour**	**Startup Hour**	**Shutdown Hour**	**PSD BACT**
$PM/PM_{10}/PM_{2.5}$	8.8	8.8	8.8	Since startup and shutdown emissions do not exceed normal operation, BACT for startup and shutdown emissions of these PSD pollutants need not be established. BACT for normal operation applies.
H_2SO_4	2.2	1.9	1.4	

Table 4 indicates an increase in hourly mass emission limits for both startup and shutdown for NO_x only. MassDEP has reviewed Footprint's December 11, 2013 and January 10, 2014 submittals appended hereto regarding the BACT analysis for startup and shutdown emissions and agrees that these emission rates contained in Table 4 represent BACT during startup and shutdown periods.

Using the worst case scenario cold starts, Footprint proposes a NO_x limit of 93.2 lb for each startup event and 19.4 lb for each shut down event. Footprint has requested that MassDEP adopt these limits as BACT. To support this request, Footprint evaluated the PSD BACT determinations for NO_x during start up and shut down at large combined cycle electric generating facilities approved during the last five years. Footprint found no currently operating facility with a more stringent NO_x limit that applies in all start-up and shut down scenarios including cold starts. Based on this analysis, MassDEP has determined that Footprint's proposed start-up and shut down NO_x limits are BACT.

Auxiliary Boiler

The proposed SHR Project will include the installation of an 80 MMBtu/hr heat input, natural gas-fired auxiliary boiler. Annual operation of the auxiliary boiler will be limited to the full load equivalent of 6,570 hours per year. The unit will be equipped with ultra-low NO_x burners for NO_x control. Emissions will be controlled through the exclusive use of natural gas as fuel, good combustion practices and a limit on the annual operations.

Footprint requested that MassDEP adopt a BACT NO_x limit of 0.011b/MMBtu. To support this request, Footprint evaluated the use of an SCR system to reduce the NO_x emissions below its proposed limit. Footprint determined that although technically feasible, an SCR would remove additional NO_x at an average cost of $19,000 per ton and an incremental cost of $70,000 per ton and thus is not cost effective. MassDEP concurs in that determination and finds that the auxiliary boiler NO_x limit of 0.011 lb/MMBtu (the limit that will be achieved without an SCR system) represents BACT for NO_x.

For $PM/PM_{10}/PM_{2.5}$ emissions, Footprint proposes a BACT limit of 0.005 lb/MMBtu. Footprint contends this BACT limit is more stringent than other recent BACT limits for natural gas-fired boilers in Massachusetts. PM BACT limits, established relatively recently, were 0.007 lb/MMBtu for auxiliary boilers at Mystic Station and Veolia MATEP, and 0.01 lb/MMBtu for Brockton Power. The PM BACT limit for the auxiliary boiler at Pioneer Valley Energy Center is comparable at 0.0048 lb/MMBtu. MassDEP concurs with Footprint's assessment of auxiliary boiler PM BACT.

Footprint proposes a limit of 0.0009 lb/MMBtu for H_2SO_4. Footprint proposes to control its H_2SO_4 emissions bycombusting solely natural gas and by limiting the sulfur content of its fuel. Footprint assumes an approximate 40% molar conversion of fuel sulfur to H_2SO_4. This conversion rate is higher than that assumed in connection with other similar units permitted in the last five years. Footprint notes that the auxiliary boiler will usean oxidation catalyst to control its CO emissions and that the collateral impact of this oxidation catalyst is an increase in H_2SO_4 emissions. Footprint identified 5 similar units with more stringent H_2SO_4 limits. Footprint points out that none of these units have an oxidation catalyst. MassDEP notes that the Mystic Station auxiliary boiler SO_2 emission limit is 0.0023 lb/MMBtu. Based on the natural gas sulfur content restriction of 0.5 grains per 100 ft^3, the proposed SO_2 emission limit is 0.0015 lb/MMBtu. H_2SO_4 emissions are assumed to be equivalent to approximately 2/3 of SO_2 emissions based on vendor data. No H_2SO_4 emission limit is cited in Mystic Station Plan Approval. MassDEP therefore concurs that a limit of 0.0009 lb/MMBtu is BACT for H_2SO_4.

The approved BACT emission limits for the auxiliary boiler are shown in Table 5.

Table 5. BACT Emission Limits for the Auxiliary Boiler

Pollutant	Emission Limitation	Control Technology
NOx	0.011 lb/MMBtu	- Ultra Low NOx Burners (9 ppm) - Good combustion practices - Natural Gas only
$PM/PM_{10}/PM_{2.5}$	0.005 lb/MMBtu	
H_2SO_4	0.0009 lb/MMBtu	Natural Gas only
GHG, CO_{2e} [1]	119.0 lb/MMBtu	Natural Gas only

Table 5 Notes:

1. BACT GHG emission limit based on 40 CFR Part 75, Appendix G, and 40 CFR Part 98, Subparts A and C (see August 20, 2013 supplement to the Application).

Emergency Generator and Fire Pump Engines

The SHR Project will include an emergency diesel generator (EDG) engine and a diesel fire pump (FP) engine. Both engines will operate on ULSD fuel. The proposed EDG will be a Cummins 750DQFAA ULSD-fired engine (or equivalent) with a standby generating capacity of 750 kW. The FP engine will be a 371 Brake Horsepower (BHP), 2.7 MMBtu/hr ULSD-fired engine. Both engines will be used in emergency situations only (with the exception of periodic maintenance/testing events) and will be limited to a maximum of 300 hours per rolling 12-month period of operation. There are no post-combustion controls that have been demonstrated in practice for small, emergency internal combustion engines. Footprint provided an analysis that showed that the installation of controls to limit the emissions from the emergency generator and fire pump engines, although technologically feasible, is not cost effective. In order to satisfy BACT requirements in these circumstances, Footprint has proposed that the EDG engine will meet the EPA Tier 2 standards and that the FP engine will meet the EPA Tier 3 standards for off-road diesel engines without the installation of add on controls. These both meet applicable federal NSPS requirements under 40 CFR Part 60 Subpart IIII, and incidentally, 40 CFR Part 89 as is specified in MassDEP's Air Pollution Control Regulation at 310 CMR 7.26(42)(b). Emissions will be controlled through the use of ULSD, good combustion practices and limited annual operation.

With the exception of emergency situations, the units will typically operate no more than one hour per week, for testing and maintenance purposes. The specific EDG and FP engines BACT emission limits are shown in Tables 6 and 7.

Table 6. Emergency Diesel Generator BACT Emission Limits				
Pollutant	**EPA Tier 2 Standard (g/kWh)**	**Emissions (lbs/hr)**	**Emissions (lb/MMBtu)**	**Emissions (tpy)**
NO_x [1]	6.4	11.60	-	1.7
$PM/PM_{10}/PM_{2.5}$	0.2	0.42 [2]	-	0.06 [2]
H_2SO_4 [3]	-	0.0009	-	0.00013
GHG, CO_{2e}	-	-	162.85	181

Table 6 Notes:

1. EPA Tier 2 standard for NO_x and VOC is 6.4 g/kWh, combined. For worst case potential emissions, NO_x emissions assumed equal to this level and VOC emissions assumed equal to the older EPA Tier 1 limit of 1.3 g/kWh.

2. Emission limit reflects the addition of approximately 0.032 g/kWh for condensable particulate to the EPA Tier 2 standard based on AP-42 ratios.

3. There is no Tier 2 limit for SO_2 emissions. SO_2 emissions are limited based upon ULSD fuel sulfur content of 0.0015 weight percent. H_2SO_4 emissions assumed equal to 8 weight percent of SO_2 emissions.

Table 6 Key:

g/kWh = grams per Kilowatt-hour
lb/hr = pounds per hour
lb/MMBtu = pounds per million British thermal units
tpy = tons per 12-month rolling period

Table 7. Diesel Fire Pump Engine BACT Emission Limits				
Pollutant	**EPA Tier 3 Standard (g/kWh)**	**Emissions (lbs/hr)**	**Emissions (lb/MMBtu)**	**Emissions (tpy)**
NO_x [1]	4.0	2.44	-	0.4
$PM/PM_{10}/PM_{2.5}$	0.2	0.14 [2]	-	0.02 [2]
H_2SO_4 [3]	-	0.0003	-	0.00005
GHG, CO_{2e}	-	-	162.85	66

Table 7 Notes:

1. EPA Tier 3 standard for NO_x and VOC is 4.0 g/KWh, combined. For worst case potential emissions, NO_x emissions assumed equal to this level and VOC emissions assumed equal to the older EPA Tier 1 limit of 1.3 g/kWh.

2. Emission limit reflects the addition of approximately 0.032 g/kWh for condensable particulate to the EPA Tier 3 standard based on AP-42 ratios.

3. There is no Tier 3 limit for SO_2 emissions. SO_2 emissions are limited based upon ULSD fuel sulfur content of 0.0015 weight percent. H_2SO_4 emissions assumed equal to 8 weight percent of SO_2 emissions.

Table 7 Key:

g/kWh = grams per Kilowatt-hour
lb/hr = pounds per hour
lb/MMBtu = pounds per million British thermal units
tpy = tons per 12-month rolling period

The BACT analysis for each PSD pollutant for all proposed emission units may be found in Appendix 1 attached to the PSD Fact Sheet.

VII. Monitoring and Testing

Footprint will install, calibrate, and operate dedicated continuous emission monitoring systems for measuring NO_x emissions, in addition to the diluent oxygen (O_2), in the flue gas from the combined cycle turbines. Each system will consist of a probe, analyzer, and data acquisition and handling system. The NO_x monitoring system shall meet the specifications and quality assurance procedures of 40 CFR Part 75. The O_2 monitoring system shall meet the specifications and quality assurance procedures of 40 CFR Part 60 Appendix B, Performance Specification 3. Emission data for NO_x will be measured by the analyzer in ppmvd (parts per million by volume, dry basis). This ppmvd data, corrected for O_2, can be directly compared to the permit emission limits to determine compliance.

Pursuant to 40 CFR 75.13, Footprint will also monitor CO_2 emissions in accordance with 40 CFR Part 75, Appendix G. To obtain NO_x mass emissions on an hourly basis, Footprint will use EPA methods contained in 40 CFR Part 75. Footprint will need to measure heat input on an hourly basis and moisture content to convert the measured ppmvd data to pounds per hour (lbs/hr).

Footprint is required to monitor and keep records of the amount of sulfur in the natural gas that is combusted in the combined cycle turbines pursuant to New Source Performance Standards 40 CFR Part 60 Subpart KKKK.

Footprint is also required to conduct stack tests for NO_x, PM, PM_{10}, $PM_{2.5}$, CO_2, and H_2SO_4 emissions within 180 days after initial firing of the combined cycle turbines.

VIII. Impact Analysis Based on Modeling

As part of its Application, Footprint submitted a dispersion modeling analysis that met the requirements of 40 CFR Part 51, Appendix W.

Footprint's consultant (Tetra Tech) conducted a refined dispersion modeling analysis to determine impact concentrations at receptors located along the SHR Project fence line and beyond. The refined analysis was based on proposed, worst case facility emission rates, and 5 years (2006-2010) of meteorological conditions. The meteorological data was collected at the Boston Logan Airport National Weather Service (NWS) station, which is the closest first order NWS station to the SHR Project and is representative of the SHR Project site area since it is exposed to similar coastal environmental conditions.

The dispersion modeling results for the proposed SHR Project are provided in Table 8 and show that the SHR Project's impact concentrations are below the corresponding Significant Impact Levels (SILs) established by EPA for all pollutants except NO_2 (1-hour) and $PM_{2.5}$ (24-hour). Compliance with the NAAQS and PSD Increments is therefore, according to EPA guidance, demonstrated for all pollutants and averaging periods for which impacts are below the SILs. Cumulative modeling with other regional sources was conducted for NO_2 and $PM_{2.5}$.

Table 8. Project Maximum Predicted Impact Concentrations Compared to Significant Impact Levels (micrograms/cubic meter)

Pollutant	Averaging Period	Maximum Predicted Salem Harbor Redevelopment Project Impact	SIL
PM_{10}	24-Hour	4.3	5
$PM_{2.5}$	24-Hour	3.2	1.2
	Annual	0.11	0.3
NO_2	1-Hour	41.8	7.5
	Annual	0.4	1

Background Concentrations and Nearby Sources

Tetra Tech determined ambient background concentrations through the use of existing ambient monitoring data representative of the SHR Project site area. Ambient background concentrations are based on the measurements made at the MassDEP monitoring site (ID# 025-009-2006) located in Lynn, MA. The Lynn monitoring site is located approximately 5.9 miles to the southwest of the project site. This monitoring site is representative of the SHR Project site since it is located relatively close to the site. Furthermore, use of data from the Lynn monitoring site is also conservative because Lynn is a more industrialized and densely populated area than the proposed SHR Project site area, particularly without the influence of the coal and residual oil fired existing Salem Harbor Station, as will be the situation when the SHR Project begins operations. The SHR Project site is located adjacent to Salem Harbor, a significantly large water body where potential emission sources are more limited. The Lynn monitoring site is also located closer to the metropolitan Boston area than the project site area. Any potentially elevated ambient background pollutant concentrations from mobile and stationary emission sources located in and around the Boston metro area that may be transported to the Salem project area (via predominant south-southwesterly winds, i.e. winds blowing towards the north-northeast), must pass the Lynn monitoring site, and are therefore represented in the measurement data collected at the Lynn monitoring site.

The GE Aircraft Engine facility in Lynn and the Wheelabrator Saugus waste-to-energy facility, two major industrial emission sources modeled cumulatively with the proposed SHR Project, are located slightly less than 2 miles from the monitoring site but are located about 7 miles from the SHR Project site. Therefore, the cumulative modeling compliance demonstration, which includes both the background ambient concentrations and impacts from the interactive existing major sources potentially double counts the contribution of these sources and therefore, potentially overestimates cumulative impact concentrations. This is particularly significant because these two major sources are located to the south-southwest of the Lynn monitoring site which means that they could potentially influence the measured site concentrations during south-southwesterly winds (winds blowing towards the north northeast) which is one of the predominant wind directions in the area.

Nearby sources that must be considered in cumulative modeling are described in 40 CFR Part 51, Appendix W as follows:

> *"Nearby Sources:* All sources expected to cause a significant concentrations gradient in the vicinity of the source or sources under consideration for emission limit(s) should be explicitly modeled. The number of expected sources is expected to be small except in unusual situations. Owing to both the uniqueness of each modeling situation and the large number of variables involved in identifying nearby sources, no attempt here is made to define the term. Rather, identification of nearby sources calls for the exercise of professional judgment by the appropriate reviewing authority (paragraph 3.0(b)). This guidance is not intended to alter the exercise of the judgment or to comprehensively define which sources are nearby sources."

The term "sources" in EPA's modeling guidance refers to stationary point sources of air emissions. Air emissions from mobile sources are addressed through the use of ambient background concentrations as measured by representative monitors. MassDEP reviewed recent emissions source inventory data for point sources of NO_x and $PM_{2.5}$ surrounding the project. In accordance with MassDEP's June 2011 "Modeling Guidance for Significant Stationary Sources of Air Pollution", nearby sources within 10 kilometers that emit significant emission rates for NO_x and $PM_{2.5}$ (40 tons per year and 10 tons per year actual emissions, respectively) may significantly interact with a new or modified facility.

The sources that were identified for inclusion in the source interaction cumulative modeling analysis include the General Electric (GE) Lynn, MA and Wheelabrator Saugus, MA facilities for both NO_x and $PM_{2.5}$ emissions, as well as the Rousselot Peabody facility (formerly Eastman Gelatin Corp.), Peabody Municipal Light (PML), and Marblehead Municipal Light (MML) facilities, for NO_x emissions only. The GE and Wheelabrator facilities are located approximately 12.1 and 11.6 km (7.5 and 7.2 miles), respectively, to the southwest of the project site. Based on the 2008 MassDEP emission source inventory data, actual GE emission levels for NO_x and $PM_{2.5}$ are 248.3 and 11.8 tons per year, respectively. Wheelabrator emission levels for NO_x and $PM_{2.5}$ are 721.8 and 6.2 tons per year, respectively. The Rousselot, PML, and MML facilities are located approximately 5.0 km (3.1 miles) to the east, 4.5 km (2.8 miles) to the northeast, and 2.1 km (1.3 miles) to the southeast of the project site, respectively. The actual 2008 NO_x emission levels for these facilities are 15.0 tons per year (Rousselot), 6.4 tons per year (PML), and 0.34 tons per year (MML). The actual NO_x emissions from these three sources are below the PSD and MassDEP significance level of 40 tons per year of NO_x, but were included in the analysis because of their proximity to the proposed SHR Project.

The results of the cumulative impact assessment, presented in Table 9, demonstrate that the proposed SHR Project's worst case emissions will result in compliance with the National Ambient Air Quality Standards (NAAQS). Note that while impacts related to secondary $PM_{2.5}$ emissions have not been explicitly quantified, sufficient margin is available between the predicted impact concentrations from direct $PM_{2.5}$ emissions and the NAAQS, that the NAAQS would not be threatened by additional $PM_{2.5}$ emissions. This conclusion is further supported by the fact that the maximum $PM_{2.5}$ impacts are predicted very close to the SHR Project fence line, where secondary $PM_{2.5}$ emissions would not have sufficient time to develop, and therefore, could only be additive to predicted project impacts where impacts of direct $PM_{2.5}$ emissions are less than what has been reported for the compliance demonstration.

Table 9. Salem Harbor Station Redevelopment Project NAAQS Compliance Assessment (micrograms/cubic meter)					
Pollutant	**Averaging Period**	**Cumulative Impact, SHR Project Plus Existing Sources [2]**	**Background [1]**	**Total Impact Plus Background**	**Primary NAAQS**
$PM_{2.5}$	24-Hour	3.5	18.9	22.4	35
NO_2	1-Hour	83.7 [3]	82.3	166.0	188

1. Background concentrations are based on the measured values from 2010 through 2012. Short term background concentrations for 24-Hour $PM_{2.5}$ and 1-Hour NO_2, are the average of the 98th percentile values over the 3 years (2010-2012). These assumptions are consistent with the form of the NAAQS for the pollutant.

2. Consistent with EPA modeling guidance for NAAQS compliance assessments, impact concentrations are based on the 5 year average of the 8th highest 24-hour average values occurring in each year for the 24-Hour $PM_{2.5}$ concentration, and the 5 year average of the 8th highest daily maximum concentrations occurring in each year for the 1-Hour NO_2 concentration.

3. The modeled cumulative impacts represent an EPA-approved Tier 2 approach reflecting an 80 percent conversion of NO_x emissions to NO_2 in the ambient air. "Tier 2" is the Ambient Ratio Method for NO_x to NO_2 conversion of AERMOD modeling results. It specifies that the results of NO_x modeling be multiplied by an empirically-derived NO_2/NO_x ratio, using a value of 0.75 for the annual standard and 0.8 for the 1-hour standard. This modeling guidance is contained in USEPA's Clarification Memo, dated March 1, 2011, "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard".

In addition to demonstrating compliance with the NAAQS, Footprint is required to demonstrate that its emission impacts will not exceed available PSD increments. No increment exists for 1-hour NO_2. On October 20, 2010, EPA published an increment standard for $PM_{2.5}$, averaged over both annual and 24-hour basis. In this rulemaking, EPA established the major source baseline date of October 20, 2010 and a requirement that all PSD $PM_{2.5}$ sources will not consume more than the available increment. For $PM_{2.5}$, increment is tracked on a county wide basis in Massachusetts. The SHR Project will be the first major source permitted in Essex County after this date, and therefore the entire increments of 9 $\mu g/m^3$ (24-Hour $PM_{2.5}$) and 4 $\mu g/m^3$ (Annual $PM_{2.5}$) are available. As shown in Table 10, the SHR 24-hour $PM_{2.5}$ and Annual $PM_{2.5}$ impacts are 33.3% and 3% of their respective PSD increments.

Table 10. Salem Harbor Station Redevelopment Project PSD Increment Compliance Assessment (micrograms/cubic meter)			
Pollutant	**Averaging Period**	**SHR Project Increment Consumption[1]**	**Maximum Allowable PSD Increment**
$PM_{2.5}$	24-Hour	3.0	9
$PM_{2.5}$	Annual	0.12	4

1. Consistent with EPA modeling guidance for PSD increment compliance assessments, impact concentrations are based on the highest 2nd high value at any receptor in any one for 24-hour $PM_{2.5}$ increment consumption and the maximum concentration at any receptor in any one year for annual increment consumption.

Impairment to Visibility, Soils, and Vegetation

40 CFR 52.21(o) requires the Applicant to conduct an analysis of the air quality impact and impairment to visibility, soils, and vegetation that would occur as a result of the SHR Project and general commercial, residential, industrial, and other growth associated with the SHR Project. The VISCREEN model was used by Tetra Tech to assess potential visibility impacts at the closest Class I Area, the Presidential Range/Dry River National Wilderness Area (185 km away). The SHR Project's maximum potential emissions were used in the analysis. MassDEP reviewed the analysis and has determined that the visibility impairment related to the SHR Project's plume will not exceed threshold criteria.

The EPA guidance document for soils and vegetation, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" (EPA Screening Procedure) (EPA 450/2-81-078) established a screening methodology for comparing air quality modeling impacts to "vegetation sensitivity thresholds." As an indication of whether emissions from the SHR Project will significantly impact the surrounding vegetation (i.e., cause acute or chronic exposure to each evaluated pollutant), the modeled emission concentrations have been compared against both a range of injury thresholds found in the guidance, as well as those established by the NAAQS secondary standards. Since the NAAQS secondary standards were set to protect public welfare, including protection against damage to crops and vegetation, comparing modeled emissions to these standards provides some indication of whether potential impacts are likely to be significant. Table 11 lists the project impact concentrations and compares them to the vegetation sensitivity thresholds and NAAQS secondary standards. All pollutant impact concentrations are below the vegetation sensitivity thresholds.

Table 11. Vegetation Impact Screening Thresholds

Pollutants	Averaging Period	Maximum Project Impacts (μg/m³)	Secondary NAAQS (μg/m³)	EPA's 1980 Screening Concentrations (μg/m³)
NO_2	4-hour	41.8 [1]	NA	3760
	1 month	41.8 [1]	NA	561
	Annual	0.4	100	94
PM_{10}	24-hour	4.3	150	None
$PM_{2.5}$	24-hour	3.2	35	None
	Annual	0.11	15	

1. Conservatively based on shorter term average predicted concentration.

The EPA Screening Procedure also provides a method for assessing impacts to soils. This assessment evaluates trace elements contamination of soils. Since plant and animal communities can be affected before noticeable accumulations occur in the soils, the approach used here evaluates the way soil acts as an intermediary in the transfer of a deposited trace element to the plants. For trace elements, the concentration deposited in the soil is calculated from the maximum predicted annual ground level concentrations conservatively assuming that all deposited material is soluble and available for uptake by plants. The amount of trace element potentially taken up by plants was calculated using average plant to soil concentration ratios. The calculated soil and plant concentrations were then compared to screening concentrations designed to assess potential adverse effects to soils and plants. Table 12 presents the results of the potential soil and plant concentrations based on Tetra Tech's analysis and compares them to the corresponding screening concentration criteria. A calculated concentration in excess of either of the screening concentration criteria is an indication that a more detailed evaluation may be required. MassDEP reviewed the analysis and has determined that concentrations as a result of operation of the proposed SHR Project are all well below the screening criteria.

Table 12. Soils Impact Screening Assessment

Pollutant	Deposited Soil Concentration (ppmw)	Soil Screening Criteria (ppmw)	Percent of Soil Screening Criteria	Plant Tissue Concentration (ppmw)	Plant Screening Criteria (ppmw)	Percent of Plant Screening Criteria
Arsenic	3.02E-04	3	0.0	4.23E-05	0.25	0.0
Cadmium	1.63E-03	2.5	0.1	1.74E-02	3	0.6
Chromium	3.78E-03	8.4	0.0	7.56E-05	1	0.0
Copper	1.23E-03	40	0.0	5.76E-04	0.73	0.1
Lead	8.30E-04	1000	0.0	3.73E-04	126	0.0
Mercury	3.71E-04	455	0.0	1.85E-04	NA	NA
Nickel	3.31E-03	500	0.0	1.49E-04	60	0.0
Selenium	7.08E-05	13	0.0	7.08E-05	100	0.0
Vanadium	3.40E-03	2.5	0.1	3.40E-05	NA	NA

Note: Based in screening procedures described in Chapter 5 of the EPA guidance document for soils and vegetation, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals."

IX. Mass Based Emission Limits

To ensure the NAAQS and PSD increment are not violated, a PSD Permit must contain enforceable permit terms and conditions which ensure the mass flow rates for each modeled pollutant are not exceeded. This is accomplished by establishing mass-based emission limits for each modeled pollutant with or without the use of a CEMS. When a CEMS is used, the PSD Permit must establish the averaging time for each mass-based emission limit that ensures compliance with the NAAQS. Without a CEMS, the applicable stack test method establishes the averaging time by default. Footprint is required to install CEMS for NO_x, therefore averaging times for NO_x are specified in the Permit.

Table 13. Mass-Based Emission Limits [1]

NO_x	$PM/PM_{10}/PM_{2.5}$
Combined Cycle Turbine (maximum capacity)	
18.1 lb/hr, one hour block average	See Table 2 in PSD Permit
Combined Cycle Turbine (start-up/shutdown)	
See Table 2 in PSD Permit	See Table 2 in PSD Permit
Auxiliary Boiler	
0.88 lb/hr, one hour block average	0.4 lb/hr, one hour block average

Table 13. Mass-Based Emission Limits [1]	
Emergency Diesel Generator	
11.6 lb/hr, one hour block average [2]	0.36 lb/hr, one hour block average [2]
Diesel Fire Pump Engine	
2.44 lb/hr, one hour block average [2]	0.12 lb/hr, one hour block average [2]

Table 13 Notes:

1. There are no mass-based emission limits for GHG since there is no NAAQS or increment to protect.

2. Includes VOC (NMHC as $CH_{1.8}$) but conservatively assumed as all NO_x.

Table 13 Key:

NO_x = Nitrogen Oxides
PM = Total Particulate Matter
PM_{10} = Particulate Matter less than or equal to 10 microns in diameter
$PM_{2.5}$ = Particulate Matter less than or equal to 2.5 microns in diameter
lb/hr = pound per hour

The PSD Permit contains the mass-based emission limits Footprint used in demonstrating compliance with the NAAQS and $PM_{2.5}$ increment, which are therefore enforceable emission limits in the PSD Permit.

X. Environmental Justice

The PSD Delegation Agreement specifies that MassDEP identify and address, as appropriate, "disproportionality high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations," in accordance with Executive Order 12898 (February 11, 1994). Footprint considered draft federal guidance[3] as well as the Massachusetts Executive Office of Energy and Environmental Affairs (EOEEA) Massachusetts-specific Environmental Justice (EJ) Policy in preparing an EJ assessment for the SHR Project. MassDEP reviewed the EJ assessment and agrees that the analysis satisfies both state and federal requirements.

The EPA defines EJ as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin or income with respect to the development, implementation, and enforcement of environmental laws, regulations and policies. Fair treatment means that no group of people, including a racial, ethnic, or socioeconomic group, should bear a disproportionate share of the negative environmental consequences resulting from industrial, municipal, and commercial operations or the execution of federal, state, local, and tribal programs and policies."[4]

3 US EPA, "Draft Technical Guidance for Assessing Environmental Justice in Regulatory Analysis", May 1, 2013 Post-Internal Agency Review Draft.

4 US EPA, Basic Information: Environmental Justice. http://www.epa.gov/environmentaljustice/basics/index.html

As demonstrated in Footprint's Application, Supplements, and as further set forth below, no such group of people will bear a disproportionate share of negative health or environmental consequences from the issuance of a PSD Permit to Footprint as (1) the SHR Project will not be located in or abutting an EJ area; (2) nearby EJ communities have been provided with several opportunities to participate in the permitting process; and (3) the SHR Project meets all applicable air emissions standards and would not cause or contribute to a violation of the health-based National Ambient Air Quality Standards. Moreover, the resulting regional emission reductions will benefit all communities, including EJ areas.

Identification of Environmental Justice Areas

The Commonwealth of Massachusetts Executive Office of Energy and Environmental Affairs (EOEEA) Geographic Information System (GIS) includes EJ areas divided by block groups based on the 2010 US Census data.[5] The block groups are based on the number of people generally ranging from 500 to 2500 people as opposed to physical boundaries such as streets or rivers. There are three main EJ classifications in the EOEEA EJ Policy (which is more expansive than the EPA policy) - Minority, Low Income, and English Isolation (referred to as "Lacking English Language Proficiency" in the EOEEA Policy):

- "Minorities" under the EOEEA Policy are individuals who refer to themselves on federal census forms as "non-white" or as "Hispanic," which is broader than the EPA EJ definition. Any block group with 25 percent or more minority population is considered to be an EJ area.

- Income of approximately 65% of the median annual household income is considered low income. In Massachusetts median income is based on the state median household income of $62,133 per year. Thus, any block group with a median annual household income of $40,673 or less is considered to be an EJ area.

- English Isolation is any household in which members 14 years old and older speak a non-English language and also speak English less than "very well" (i.e., are not proficient in English). Any block group with 25% or more of households as English Isolated is considered to be an EJ area.

Based on EJ mapping completed by EOEEA, the SHR Project does not abut any EJ areas and is not located within 1 kilometer of any EJ areas. However, the site is within approximately 10 kilometers of a number of EJ communities in Salem, Lynn, Peabody, Danvers and Beverly. The closest EJ areas are classified as Minority/Low Income and Minority/Low Income/English Isolation and are located approximately 1.2 kilometers (¾ of a mile) to the southwest of the SHR Project property boundary. A portion of this area is known as the "Point Neighborhood."

The Point was originally surrounded by water on three sides and was known as Long Point or Stage Point. There were fish shacks and mill buildings in this area originally. In the mid-1880's the Naumkeag Steam Cotton Company built its first mill along the South River in the area of current day Shetland Park. Immigrants, mainly French Canadians, settled in this area and provided the labor force for the textile mills. The area was filled in to provide housing and more mill buildings. The Great Salem Fire of 1914 destroyed this area but it was quickly rebuilt. The area thrived until the 1950's when

5 2010 census data is the latest demographic data available. http://www.mass.gov/mgis/ej_boston_metro.pdf

the textile industry moved to the south. Over the past few decades, many Spanish-speaking immigrants have settled in this area.

There are several additional areas in Salem located further than 10 km from the SHR Project property and these are classified as containing low income and minority populations.

Public Participation

MassDEP published the Notice of Public Hearing and Public Comment Period on the Draft PSD Permit in English, Spanish, and Portuguese. A translator was provided at the Public Hearing. Upon request, copies of the public record would be provided in Spanish and Portuguese.

Footprint has conducted informational meetings, answered questions, and translated presentations in non-English languages, in response to public interest and to encourage public participation. The following is a summary of the public outreach, including outreach to EJ communities, conducted over the past year.

Notification of Filing an Environmental Notification Form (ENF) under the Massachusetts Environmental Policy Act (MEPA) – August, 2012

A legal notice of the availability of the ENF was published in the Salem News in English, Spanish and Portuguese on August 8, 2012. It was also published in the Marblehead Reporter in English on August 9, 2012. Additional publication of the Legal Notice of Environmental Review was published in English, Spanish and Portuguese in the Boston Globe on August, 18, 2012, the Lynn Daily Item on August 21, 2012 and in the Danvers Herald, the Beverly Citizen and the Peabody-Lynnfield Weekly News on August 23, 2012.

- Energy Facilities Siting Board (EFSB) Public Hearing, Salem MA – September 19, 2012

  The following actions were taken by Footprint for the EFSB Hearing:

  - Placed Notification advertisements in both English and Spanish in the Boston Globe, Salem News, and Spanish Paper El Mundo.

  - Placed English and Spanish Legal Notice of the of EFSB Petition, stating Footprint's Development plans and the date/location of upcoming EFSB hearings, in the following locations: Salem Public Library, City Clerk's Office, North Shore Community Development Coalition, Salem Housing Authority, and ABE/ESOL Training Resources of America (Salem Office). English copies of the EFSB Petition were also placed in these locations. Notification of the placement of these EFSB documents in both English and Spanish was placed in the EFSB advertisements in all three papers.

  - Mailed EFSB Notice to abutters of existing Salem Harbor Station.

  - Retained services of Spanish translator for EFSB hearings, to both translate information as it was presented, and to translate questions presented from the public in Spanish.

- Offered to meet with interested members of the public along with Spanish translator.

- Presentation to Historic Derby Street Neighborhood Association, November 12, 2012

In addition to the presentation, Footprint offered to Linda Haley, Chairperson, that its representatives would meet with individual residents to answer questions if requested.

- Draft Environmental Impact Report, December 2012

Notice of the public scoping meeting and site visit was sent to Beverly, Lynn, Salem, Peabody, Marblehead, and Danvers. Notification of the availability of the Draft Environmental Impact Report was published in the Boston Globe, the Salem News, the Marblehead Reporter, the Beverly Citizen, the Danvers Herald, the Lynn Daily Item and the Peabody-Lynnfield Weekly News in English, Spanish and Portuguese. These notices appeared on December 19 and December 20, 2012 with the exception of the Marblehead Reporter notice which appeared on December 27, 2012.

- Presentation to the Salem Harbor Power Plant Stakeholders Group, January 22, 2013

Members have been appointed by Salem Mayor Kim Driscoll. The Stakeholders are those individuals who represent abutters to the plant, city officials whose position speaks for abutters (e.g., City Councilors, state elected officials, etc.). Footprint has made a pledge to respond to all requests for information (English or Spanish), and to openly discuss Community needs and requests.

- Presentation to The Point Neighborhood Association, February 25, 2013

Lucy Curchado, Chairperson. Footprint provided a Spanish Translator. The presentation was translated to Spanish sentence for sentence by the translator. Much of the Point leadership attended the meeting and many questions were asked. The translator obtained questions from the Point membership, translated those questions into English so they could be answered by Footprint representatives, and then translated back into Spanish in response to the questioner. Footprint offered to either meet with any members and provide a Spanish interpreter, or to respond in writing (Spanish) to questions if submitted.

- Public Presentation at the Bentley Elementary School, February 26, 2013

At Mayor Driscoll's request, Footprint made a presentation to the general public. The public was invited to ask questions and/or request additional information.

- Final Environmental Impact Report, April 4, 2013

Notification of the availability of the Draft Environmental Impact Report was published in the Boston Globe, the Salem News, the Marblehead Reporter, the Beverly Citizen, the Danvers Herald, the Lynn Daily Item and the Peabody-Lynnfield Weekly News in English, Spanish and Portuguese on April 4, 2013.

- Salem Planning Board Meetings, May 2, 2013, May 6, 2013, and June 6, 2013

These meetings were continued to June 20, 2013 and were held at Bentley Elementary School. They were open to the public.

- Ongoing coordination with Lucy Curchado, Chairperson of the Point Neighborhood Association

Footprint is in the process of translating its most recent/complete power point presentation into Spanish for distribution to the membership. Footprint has offered to translate, provide information, and/or respond to any other issues, questions or concerns of the Neighborhood Association.

Impact Analysis

Prior to 1949 the site was used for commercial purposes related to the handling of coal and oil. The first power plant built on the site was a coal-fired unit that commenced operation in 1951. A second coal-fired generation unit commenced operation in 1952, and a third coal-fired unit was added in 1958. In 1978 a fourth, oil-fired, unit was added. The existing facility has operated as a grandfathered facility (that did not have to meet emissions standards applied to new power plants) for many years and may not have been able to be built under today's environmental regulations. However, the existing facility did provide a significant economic value to the residents of Salem in tax payments. The proposed SHR Project will result in significant decreases of air pollutant emissions, not just as compared with the existing facility, but also regionally, while providing a tax benefit to the City of Salem and its residents.

Once operational, the SHR Project will be among the most efficient fossil-fueled fired electric generators in the Northeast Massachusetts (NEMA) zone and is expected to provide 5.1 million MWh of electricity annually. This additional supply will reduce the need for generation from other power plants with lower efficiency and higher operating costs, primarily fueled by natural gas, oil, and coal. Charles River Associates, a consultant to Footprint, has conducted an analysis projecting the operation of the New England bulk power system over the period 2016-2025, for scenarios with and without the SHR Project in service, and quantified the expected changes in air emissions by the project directly and the associated reductions of emissions at competing plants elsewhere in New England and, in particular, Massachusetts. MassDEP has reviewed the CRA study and agrees that because the SHR Project would displace other, less efficient generation on the New England grid, operation of the SHR Project would reduce regional GHG emissions.

Health Risk Assessment

Footprint commissioned a health risk assessment (HRA) to assess the potential for human health risk associated with the SHR Project.[6] Gradient Corporation prepared the human health risk assessment evaluating the likelihood of both acute non-cancer health risks and chronic non-cancer and cancer health risks that may result from people's inhalation of airborne pollutants for SHR Project stack air emissions. Gradient also collected relevant background health information for Salem and surrounding communities to determine if any types of disease (*e.g.*, cancer and asthma) were higher than expected compared to Massachusetts as a whole.

6 Gradient Corporation, "Health Risk Assessment (HRA) for the Salem Harbor Redevelopment (SHR) Project", January 4, 2013.

Footprint states that the HRA indicates that maximum predicted air levels of specific substances associated with SHR Project air emissions would not be expected to contribute to adverse health effects among potentially affected populations. Footprint states that several separate lines of evidence from the HRA support the conclusion that the potential air emissions from the SHR Project are not expected to have an adverse effect on public health in the Salem area. Footprint states that these include the following:

- The maximum cumulative air concentrations (project impact plus existing background) of the criteria pollutants of concern, which include SO_2, CO, NO_2, and PM, are well below the health-protective NAAQS. NAAQS are set to protect human health with a wide margin of safety even for sensitive populations. Stack emissions of criteria air pollutants are thus not expected to lead to impacts on human health (*e.g.*, asthma, cardiovascular and respiratory diseases) in nearby communities, even in sensitive populations.

- For possible non-cancer effects, all hazard quotients (HQs), calculated for an off-site resident exposed to maximum modeled incremental SHR Project stack impacts, were well below unity (HQ = 1), with none being higher than HQ = 0.01. The overall summed HI for SHR Project stack emissions is also well below 1.0, *i.e.*, HI = 0.08. These results help assure that non-cancer, adverse health effects are not to be expected from the non-criteria air-pollutant emissions.

- Conservatively projected cancer risks for maximum modeled SHR Project stack impacts of possible carcinogenic chemicals were well below the 1 in 10,000 to 1 in 1,000,000 lifetime risk range, which is considered to be acceptably low by EPA. The overall summed cancer risk from the SHR Project was about 1 in 10,000,000 over a lifetime, which is well below the EPA *de minimis* risk level. The individual pollutant cancer risks were each even lower than the *de minimis* level, between about 1 in 10,000,000,000 and about 4 in 100,000,000. These results support *de minimis* cancer risk from worst-case chronic exposures to maximum modeled SHR Project stack impacts.

- Based on the air-modeling results, short-term SHR Project air emissions impacts are not expected to give rise to acute health effects. SHR Project-related maximum short-term concentrations of NO_2 were compared to short-term exposure guidelines and standards, including the short-term NAAQS for NO_2 which were specifically designed to protect against asthma exacerbation and respiratory irritation. The comparisons show that the cumulative impact (maximum 1-hour plus ambient background) for NO_2 is well below the 1 hour health-protective NAAQS as well as other short-term exposure guideline levels.

- Gradient stated that review of community health data for Salem and nearby communities confirms that the Salem area has overall similar rates of asthma, cardiovascular conditions, and cancer compared with the state as a whole. In combination with the results of the HRA, Gradient concluded that air emissions from operation of the proposed SHR Project are not expected to significantly alter any of these baseline health statistics.

Additional Analysis of Surrounding Areas

The maximum criteria air pollutant impacts from the SHR Project were also compared to the EPA- and MassDEP-adopted significant impact levels (SILs). SILs are impact levels set at only a few percent of the ambient air quality standards and below which the regulatory agencies consider impacts to be insignificant.[7] Impacts above the SILs are not considered significant, per se, but rather additional modeling is required to demonstrate that the proposed project will not exceed the NAAQS. A significant impact area (SIA) is the area of a circle having the radius of the maximum distance from a source to the point at which concentrations drop below the SIL. The SIA is used as a basis for analysis not because of any concern that emissions impacts *inside* the SIA are adverse - since they are below the NAAQS, they are by definition *not* adverse - but rather because impacts *outside* the SIA are so insignificant as to be *de minimis.* In EJ analyses, the SIA is often presented on a direction specific basis and represents all receptors with projected impacts above the SIL.

The dispersion modeling completed for the SHR Project and described elsewhere in this Fact Sheet, demonstrates that the predicted maximum impacts from the SHR Project for the majority of criteria air pollutants are below the SILs at all locations and therefore, represent no adverse human health or environmental effects to Salem and outlying communities. The predicted impacts of the SHR Project result in slight to moderate exceedances of SILs for only $PM_{2.5}$ (24-hour average concentrations), and NO_2 (1-hour concentrations). Since the SILs are set considerably lower than the NAAQS, the modeled emissions do not necessarily mean a project's impacts would be unhealthy or would have an adverse effect on any population. Footprint evaluated these as a way to determine if an EJ area would be disproportionately subject to higher air impacts than other segments of the community at large.

The following sections describe the maximum modeled impacts for the only two pollutants with maximum impacts exceeding their respective SIL with specific reference to the SIAs in reference to nearby EJ areas versus other nearby areas.

NO_2 Analysis

The 1-hour NO_2 SIL is 7.5 $\mu g/m^3$. The 1-hour NO_2 isopleths (i.e., maximum pollutant impact concentration contours associated with emissions from the SHR Project) were prepared for the Salem region and these isopleths show the following:

- There are two small areas of isolated peak NO_2 one-hour concentrations (in the range of 36 to 42 $\mu g/m^3$ and well below the NAAQS of 188 $\mu g/m^3$). These are located very close to the SHR Project site to the northeast and southwest of the power plant stack. These areas are not close to any EJ areas. (How far are they from an EJ area?)

- Maximum concentrations beyond approximately 1 kilometer from the SHR Project's main stack are less than approximately 16 $\mu g/m^3$ and thus are all less than 10% of the health based NAAQS. However, the SIA of 7.5 $\mu g/m^3$ extends as far as 14 kilometers beyond the Footprint property

7 For example, the 1-hour NO_2 SIL is 7.5 microgram per cubic meter versus the health based standard of 188 micrograms per cubic meter and the 24 hour $PM_{2.5}$ SIL is 1.2 microgram per cubic meter versus the health based standard of 35 micrograms per cubic meter. These SIL concentrations are only 3 to 4 percent of the NAAQS.

line extending into Salem, Beverly, Marblehead, Middleton, Wenham, Danvers, Peabody, Lynn, and Swampscott. While this encompasses all of the EJ areas in Salem as well as some in Beverly, Danvers, Middleton and Lynn, the population associated with the EJ areas within the SIA is a small percentage of the total population within the SIA.

The results of this assessment demonstrate that the SHR Project's NO_2 impact concentrations will not have disproportionately high human health or environmental effects on EJ areas.

$PM_{2.5}$ Analysis

Isopleths of maximum 24-hour average predicted concentrations from the SHR Project were also prepared. These isopleths show the following:

- The highest 24-hour $PM_{2.5}$ concentrations are only a small fraction of the health based NAAQS (3 to 4 µg/m^3 compared to the 35 µg/m^3 NAAQS). These areas of highest impact are localized and generally occur either on plant property, in areas immediately adjacent to the site, or in Salem Harbor adjacent to the Salem shoreline.

- The 24-hour $PM_{2.5}$ SIL is 1.2 µg/m^3 and this SIA encompasses a two city block area of a low income EJ area just south of the South River. However, the vast majority of the SIA is within Salem Harbor or consists of residences and businesses in the Salem downtown area along Derby Street. It also encompasses Winter Island and a portion of the Salem Willows Park. The EJ area represents a very small percentage of the total population within the SIA.

The results of this assessment demonstrate that the SHR Project's $PM_{2.5}$ emissions will not have disproportionately high human health or environmental effects on EJ areas.

CO_2 Benefits

The EPA's May 1, 2013 Draft EJ Guidance states, "The U.S. Climate Change Science Program stated as one of its conclusions: The United States is certainly capable of adapting to the collective impacts of climate change. However, there will still be certain individuals and locations where the adaptive capacity is less and these individuals and their communities will be disproportionally impacted by climate change. Therefore, these specific population groups may receive benefits from reductions in greenhouse gas (GHG) emissions." Operation of the SHR Project is actually projected to *reduce* (on a net basis) annual regional GHG emissions.

Conclusion

The proposed SHR Project is not located in or adjacent to an EJ area, and MassDEP hereby finds that there will be no disproportional adverse health or environmental impact to any such community. Footprint has demonstrated that emissions from the proposed SHR Project itself will be well within the NAAQS, which are designed to be health-protective of the most sensitive populations.

The above-discussed analyses and actions fulfill MassDEP's obligations under the Delegation Agreement and fulfill all obligations under Executive Order 12898 and EPA Environmental Justice Policy.

XI. National Historic Preservation Act, Endangered Species Act, Tribal Consultation

Section IV of the PSD Delegation Agreement contains the requirements for Applicants (e.g., Footprint), MassDEP, and EPA with regards to the PSD Program. Under the PSD Delegation Agreement, EPA must engage in consultation as required by federal law before MassDEP issues PSD Permits.

Section IV.H.3. states that "If EPA requires more time to consult with an Indian tribe before issuance of a Draft PSD Permit, refrain from issuing the Draft PSD Permit until EPA informs MassDEP that it may do so." In addition, Section IV.H.4. states that "In all cases, MassDEP will refrain from issuing any Final PSD Permit until EPA has notified MassDEP that EPA has satisfied its NHPA, ESA, and Tribal consultation responsibilities with respect to that Permit."

In an April 18, 2013 letter from Tetra Tech to EPA Region 1, Tetra Tech asked EPA to notify MassDEP that EPA has satisfied its consultation responsibilities for the proposed SHR Project's PSD Permit. The letter included several attachments sent to various State, Federal and Tribal agencies responsible for their respective National Historic Preservation Act (NHPA), Endangered Species Act (ESA), and Tribal programs. EPA Region 1 reviewed Tetra Tech's letter and attachments and concluded in its September 5, 2013 letter to MassDEP that it had satisfied its NHPA, ESA, and Tribal consultation responsibilities with respect to Footprint's PSD Permit.

The following sections outline how the NHPA, ESA, and Tribal consultation requirements identified under the PSD Delegation Agreement have been met.

<u>National Historic Preservation Act</u>

On August 18, 2013, Tetra Tech submitted a letter to the Massachusetts Historic Commission (MHC) notifying the MHC of Footprint's submittal of a PSD Permit Application for the proposed SHR Project. The letter explained that Tetra Tech reviewed the National and State Register files and the Inventory of Historic and Archaeological Assets of the Commonwealth at the MHC. The file search did not identify any previously identified historic or archaeological resources within the proposed SHR Project site.

The proposed SHR Project was also subject to a full Massachusetts Environmental Policy Act (MEPA) review. As part of the MEPA review, a MEPA Environmental Notification Form (ENF) was distributed to the MHC in August 2012. The MHC did not submit comments on the ENF to the MEPA office. Accordingly, EPA found that NHPA consultation requirements for the proposed SHR Project have been satisfied.

Endangered Species Act

Section 7 of the Endangered Species Act (ESA) requires that certain federal actions such as federal PSD Permits address the protection of endangered species in accordance with the ESA.

On April 18, 2013, Tetra Tech submitted a letter to Thomas R. Chapman, Supervisor, New England Fish and Wildlife Service (FWS) field office notifying the FWS office of Footprint's submittal of the PSD Permit Application for the proposed SHR Project. The letter stated that Footprint is aware of and understands current ESA consultation procedures outlined on the FWS website. The website provides an endangered species consultation process in which the Applicant conducts the initial consultation. Tetra Tech reviewed the data for Essex County and identified two endangered species, the small whorled Pogonia plant and the piping plover. Tetra Tech determined the presence of the two species is limited to either the woodlands or the coastal beaches and are not present in the City of Salem where the proposed SHR Project will be located. Tetra Tech concluded that the proposed SHR Project does not pose a threat to any currently identified or proposed endangered species or their habitats in the area subject to FWS jurisdiction and as a result, no further ESA impact analysis is required. In a November 28, 2012 letter from Thomas R. Chapman, FWS, to Lisa Carrozza, Tetra Tech, FWS confirmed that no federally listed, proposed, threatened or endangered species or critical habitat are known to occur in the proposed SHR Project area and that no further ESA coordination is necessary.

In addition, on April 18, 2013, Tetra Tech submitted a letter to John Bullard, Regional Administrator, National Oceanic and Atmospheric Administration (NOAA) National Marine Fisheries Service (NMFS), Northeast Regional Office, which notified (NMFS) of the PSD Permit Application submittal. The letter described the proposed SHR Project and its location at the existing Salem Harbor Station and concluded that the changes will reduce net regional emissions of air pollutants due to displacement of other, less efficient electrical generation on the New England electric grid.

Based on the letters to FWS and NMFS, EPA found that ESA consultation requirements for the proposed SHR Project had been satisfied.

Tribal Consultation

On April 18, 2013, Footprint submitted separate letters to the Tribal Environmental Directors and the Tribal Historic Preservation Officers for the Wampanoag Tribe of Gay Head (Aquinnah) and Mashpee Wampanoag Tribe. The letters notified the Tribes of the proposed SHR Project's PSD Permit Application and described how the proposed SHR Project will reduce net regional emissions of air pollutants due to displacement of other, less efficient electrical generation on the New England electric grid. In addition, EPA notified the tribes about Footprint's proposed SHR Project in a follow-up E-mail message. As of this date, neither Tetra Tech nor EPA has informed MassDEP of receipt of any comments from the Tribes.

XII. Comment Period, Hearings and Procedures for Final Decisions

All persons, including Applicants, who believed any condition of the Draft Permit was inappropriate were required to raise all issues and submit all available arguments and all supporting material for their arguments in full by the close of the public comment period, November 1, 2013, to Cosmo Buttaro of MassDEP at the address listed in Section XIII of this Fact Sheet.

A public hearing was held during the public comment period. MassDEP extended the public comment period for three additional weeks to November 1, 2013. In reaching a final decision on the PSD Permit, MassDEP has responded to all significant comments and is issuing a Response to Comments (RTC) document concurrently with this PSD Fact Sheet and the PSD Permit.

MassDEP is forwarding a copy of the PSD Permit, PSD Fact Sheet and RTC to the Applicant and each person who has submitted comments or requested notice.

Along with the PSD Permit, each person is being notified of their right to appeal, in accordance with 40 CFR 124.15 and 124.19 via the following language:

1. Within 30 days after the final PSD Permit decision has been issued under 40 CFR 124.15, any person who filed comments on the Draft Permit or participated in any public hearing may petition EPA's Environmental Appeals Board to review any condition of the Permit decision.

2. The effective date of the Permit is 30 days after service of notice to the Applicant and commenters of the final decision to issue, modify, or revoke and reissue the Permit, unless review is requested on the Permit under 40 CFR 124.19 within the 30 day period.

3. If an appeal is made to the EAB, the effective date of the Permit is suspended until the appeal is resolved.

XIII. MassDEP Contacts

Additional information concerning the PSD Permit may be obtained between the hours of 9:00 a.m. and 5:00 p.m., Monday through Friday, excluding holidays from:

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APPENDIX 1

BEST AVAILABLE CONTROL ANALYSIS (BACT)

APPENDIX A
EMISSIONS CALCULATIONS

1.0 CONTROL TECHNOLOGY ANALYSIS

This section presents an updated PSD BACT analysis for the Project. This updated analysis addresses comments made on the draft permit and reflects additional information and corrections. The Project exceeds PSD significant emission thresholds for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, and thus is subject to PSD BACT for these pollutants. The Project does not exceed PSD significant emissions thresholds for CO.

The Project remains subject to MassDEP BACT for all pollutants. The MassDEP BACT analysis as reflected in the prior application materials and the MassDEP draft permit documents remains valid and is not addressed here. This section specifically addresses PSD BACT requirements.

PSD BACT is defined in 40 CFR 52.21 means "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

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

However, a key exception to the strict, five-step "top-down" approach is described in page B-8 of the EPA's October 1990 draft New Source Review Workshop Manual (the "NSR Manual," as cited in the EPA comment letter):

> If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.

1.1 Combined Cycle Combustion Turbines

1.1.1 Fuel Selection

Fuel selection is an important consideration with respect to all pollutants subject to PSD review for the facility (NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG). Therefore, fuel selection for the combustion turbine combined cycle units is initially discussed here, prior to the PSD BACT evaluation for the individual PSD pollutants, instead of repeating this under the evaluation for each pollutant.

The Applicant proposes to use natural gas only for the combined cycle turbines.

Step 1: Identify all control technologies (fuel types).

Identified control technologies (fuel types) for combustion turbine combined cycle units are:

1. Use of natural gas only.
2. Primarily natural gas with liquid fuel as a backup fuel. Liquid fuel could be ultra-low sulfur distillate (ULSD), biodiesel or a mixture of these.

Step 2: Eliminate technically infeasible options

Both above fuel options are technically feasible. An acceptable mixture for ULSD/biodiesel is subject to confirmation by turbine suppliers.

Step 3: Rank remaining control technologies by control effectiveness.

Natural gas is the lowest emitting commercially available fuel for combustion turbine combined cycle units. ULSD and biodiesel have higher emissions than natural gas for NO_x, $PM/PM_{10}/PM_{2.5}$ and GHG. H_2SO_4 emissions depend on the maximum sulfur content of the fuel. ULSD and biodiesel are normally specified at 15 ppm sulfur by weight, and pipeline natural gas is defined by USEPA in 40 CFR 72.2 to have a maximum sulfur content of 0.5 grains/100 scf. These values are effectively identical in the amount of sulfur per MMBtu of fuel. However, natural gas as delivered is likely to have a lower actual sulfur content per MMBtu of fuel compared to ULSD or biodiesel.
Since natural gas is a lower emitting fuel than ULSD or biodiesel, it ranks higher in terms of control effectiveness and is considered the top BACT alternative.

Step 4: Evaluation of Collateral Impacts

Energy Impacts

Within the past decade, natural gas has become increasing abundant in the New England, due to increased availability of domestic sources of gas. However, concerns have been raised regarding the lack of regional fuel diversity and potential overreliance on natural gas for energy supplies. In particular, pipeline infrastructure to deliver gas into New England can become constrained during cold weather as space heating and electric production compete for available gas supplies. These issues have resulted in considerations for more energy diversity and backup liquid fuel supplies for electric generation facilities.
Since the Applicant has committed to use natural gas exclusively in the combustion turbine combined cycle units, potential energy concerns with exclusive natural gas use are an important consideration. The Project will obtain natural gas from its direct connection to Algonquin's HubLine interstate natural gas pipeline near HubLine's interconnection with the Maritimes & Northeast Pipeline. This unique interconnection point permits the Project to access supplies of natural gas from both Canadian sources as

well as from domestic sources the south and west. The Maritimes & Northeast Pipeline has not had the same physical delivery constraints as the heavily relied-upon pipelines delivering natural gas into New England exclusively from the south and west. Therefore, energy concerns due to exclusive natural gas use are not problematic for this Project.

Economic Impacts

Natural gas is currently a much more favorable economically compared to liquid fuels, and this situation is expected retain this current pattern into the foreseeable future. With Footprint's access to Canadian Maritime gas, potential short-term price spikes due to physical supply constraints are not expected to be problematic. Therefore, there are no economic considerations that would dictate that backup provisions for liquid fuel are necessary.

Environmental Impacts

In addition to being a higher emitting fuel for air emissions, liquid fuel has other significant collateral impacts compared to natural gas. The most significant collateral impact is associated with the truck delivery of liquid fuel to the site. Although liquid fuel could be delivered by barge as well, the local community has expressed its strong opposition to the continued storage and combustion of liquid fuel on the site for power generation. These impacts are of significant concern to the local Salem community, and in fact have led to a commitment by the Applicant not to use liquid fuel for the combustion turbine combined cycle units at the site.

The other collateral environmental impact of note is the fact that NO_x control for liquid fuel requires the use of water or steam injection to the turbine combustor. The use of water/steam injection would result in a significant consumptive water use and an associated discharge of water that is not needed for dry low-NO_x combustors, which are available for natural gas.

Step 5: Select BACT

Use of natural gas as the exclusive fuel for the combustion turbine combined cycle units is clearly justified as PSD BACT. Natural gas is lower emitting, has significantly lower collateral environmental impacts, and collateral energy and economy impacts have been determined to be acceptable.

1.1.2 PSD Best Available Control Technology Assessment for NO_x

Step 1: Identify Candidate Technologies

NO_x control technologies identified for new large > 100 MW combined cycle turbines are as follows:

- Dry-low NO_x (DLN) Combustion: Turbine vendors offer what is known as lean pre-mix combustors for natural gas firing which limit NO_x formation by reducing peak flame temperatures.
- Water or Steam Injection: Water or steam injection has been historically used for both gas and oil fire turbines, but for new turbines is generally only used for liquid fuel firing.
- Catalytic Combustors: A form of catalytic combustion to limit firing temperature has been under development using the trade name XONON.
- SCONOx: This is an oxidation/absorption technology using hydrogen or methane as a reactant. This technology is currently marketed as EMx.

- SCR: This is a catalytic reduction technology using ammonia as a reactant that has been in widespread use on new combined cycle turbines for over 20 years.

Step 2: Eliminate Infeasible Technologies

Catalytic combustors are not currently technically feasible for large turbines. The only known application is on a 1.4 MW test turbine. The largest turbine to which SCONOx has been successfully demonstrated is a 43 MW turbine in California. There are significant SCONOx scale up questions for a new turbine larger than 100 MW, but for the sake of argument SCONOx will be assumed to be technically feasible here. The other technologies are all technically feasible.

Step 3: Rank Control Technologies by Control Effectiveness

The ranking of these technologies is as follows:

1. SCR: Widely demonstrated to have achieved 2.0 ppmvd NO_x at 15% O_2 for gas firing. This is documented in the LAER analysis presented in the December 21, 2012 Application and First Application Supplement (April 12, 2013).
2. SCONOx: Demonstrated to have achieved 2.5 ppmvd NO_x at 15% O_2 at the 43 MW California unit.
3. DLN: Generally recognized to achieve 9 ppmvd NO_x at 15% O_2. Commonly used in conjunction with SCR to achieve 2.0 ppmvd NO_x at 15% O_2.
4. Steam/Water Injection: Less effective than DLN.

Step 4: Evaluate Controls

Since Footprint is proposing the "top" level for NO_x BACT (SCR), the BACT analysis can proceed to the consideration of whether any collateral energy or environment impacts would indicate other than the top demonstrated technology be selected.

The one collateral impact that has been identified for SCR is due to the use of ammonia as a reagent, and the resulting emissions of ammonia "slip" that can occur. SCONOx does not require the use of ammonia. While SCONOx will eliminate the use of ammonia, the lower NO_x emissions demonstrated in practice with SCR (2.0 ppmvdc vs. 2.5 ppmvdc for SCONOx) and the very high additional cost documented with SCONOx does not justify a finding that SCONOx is BACT. This same conclusion is found in the EPA Analysis for the Pioneer Valley Energy Center (PVEC), in the Fact Sheet published in December 2011. SCONOx is not justified as BACT. In addition, as documented in the Application and supplements, the predicted ambient air quality impacts for ammonia are well below the MassDEP air toxics guidelines. Aqueous ammonia will be stored in a 34,000 gallon above ground tank located within a concrete dike designed to contain 110% of the total tank volume. Passive evaporative controls will be used inside the dike to control evaporation in the event of a release, and the tank and dike will be in a fully enclosed and sealed structure except for roof vents. Evaluation of a hypothetical worst case release indicates that ammonia concentrations at and outside the Project perimeter will be less than the ERPG-1 level. ERPG-1 is defined as the maximum airborne concentration below which nearly all individuals could be exposed for up to one hour without experiencing other than mild transient adverse health effects or perceiving a clearly defined, objectionable odor.

Step 5: Select BACT

The Footprint Project will meet the same 2.0 ppmvdc NO_x limit as determined to be BACT for PVEC. The Project will also meet a stringent emission limit for ammonia slip (2.0 ppmvdc on a 1-hour basis), which is the most stringent ammonia limit achieved in practice for facilities of this type. This stringent ammonia limit assures that collateral impacts are adequately minimized for the use of SCR for the Footprint Project, and that this represents BACT for NO_x.

1.1.3 PSD Best Available Control Technology Assessment for $PM/PM_{10}/PM_{2.5}$

Emissions of particulate matter result from trace quantities of ash (non-combustibles) in the fuel as well as products of incomplete combustion. Conservatively, all particulate matter (PM) emissions for the combustion turbines are assumed to be less than 2.5 microns in size ($PM_{2.5}$).

Pursuant to identifying candidate control technologies under the "top-down" procedure, Footprint has compiled all the PSD BACT determinations in the last five years for new large (> 100 MW) combustion turbine combined cycle project. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. The Brockton Energy Center Project in Brockton MA is also included, since it is a similar recent project in Massachusetts, even though it did not receive a PSD permit. This review confirms that the only BACT technology identified for large natural gas fired combined cycle turbines is use of clean fuel (i.e., natural gas) and good combustion practices.

For $PM/PM_{10}/PM_{2.5}$, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for $PM/PM_{10}/PM_{2.5}$. Post-combustion particulate control technologies such as fabric filters (baghouses), electrostatic precipitators, and/or wet scrubbers, which are commonly used on solid fuel boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create adverse backpressure for turbine operation.

The "top-down" procedure does require selection of BACT emission limits, which is addressed in the following paragraphs.

Table 1-1 presents the results of RBLC compilation for $PM/PM_{10}/PM_{2.5}$. A review of Table 1-1 indicates that $PM/PM_{10}/PM_{2.5}$ emission limits are expressed strictly in lbs/hr or lb/MMBtu, or in both lb/hr and lb/MMBtu. This review also indicates that different emission limits can be associated with different turbine suppliers. This is illustrated by some projects which have one set of limit for one supplier and another set of limits for another supplier.

It is Footprint's conclusion based on review of available information that differences in $PM/PM_{10}/PM_{2.5}$ emission limits among various projects are due to different emission guarantee philosophies of the various suppliers, and are not actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions inherently produced by the supplier of the turbine. The different emission guarantee philosophies are influenced by the overall uncertainties of the $PM/PM_{10}/PM_{2.5}$ test procedures, especially given reported difficulties in achieving test repeatability, and concerns with artifact emissions introduced by the general inclusion of condensable particulate emissions (as measured by impinger based techniques) in permit limits in the last decade.

Table 1-1. Summary of Recent Particulate PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] $PM/PM_{10}/PM_{2.5}$
Carroll County Energy	Washington Twp., OH	11/5/2013	2 GE 7FA 2045 MMBtu/hr/unit plus 566 MMBtu/hr DF	12.4 lb/hr/unit and 0.0108 lb/MMBtu without DF 19.8 lb/hr and 0.0078 lb/MMBtu with DF
Renaissance Power	Carson City, MI	11/1/2013	4 Siemens 501 FD2 units 2147 MMBtu/hr/unit each with 660 MMBtu/hr DF	9.0 lb/hr/unit and 0.0042 lb/MMBtu (with and without DF)
Langley Gulch Power	Payette, ID	08/14/2013	1 - Siemens SGT6-5000F 2134 MMBtu/hr/unit with 241.28 MMBtu/hr DF	12.55 lb/hr (w/ and w/o DF)
Oregon Clean Energy	Oregon, OH	06/18/2013	2 Mitsubishi M501GAC or 2 Siemens SCC6-8000H 2932 MMBtu/hr/unit plus 300 MMBtu/hr DF	Mitsubishi: 11.3 lb/hr/unit and 0.00384 lb/MMBtu without DF Mitsubishi: 10.1 lb/hr and 0.00373 lb/MMBtu with DF Siemens: 14.0 lb/hr/unit and 0.0055 lb/MMBtu without DF Siemens: 13.3 lb/hr and 0.0047 lb/MMBtu with DF
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	2 GE 7FA.05 2230 MMBtu/hr/unit plus 650 MMBtu/hr DF or 2 Siemens SGT6-5000F5 2260 MMBtu/hr/unit plus 450 MMBtu/hr DF	GE: 0.00334 lb/MMBtu at full load (w/ and w/o DF) 9.6 lb/hr/unit without DF 16.2 lb/hr with DF Siemens: 0.00374 lb/MMBtu at full load (w/ and w/o DF) 10.1 lb/hr/unit without DF 14.5 lb/hr with DF
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	GE7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H. 2 combined cycle units	11.0 lb/hr/unit without DF 18.5 lb/hr/unit with DF Emissions based on Siemens SGT6-8000H
Sunbury Generation	Sunbury, PA	04/01/2013	“F Class” with DF 2538 MMBtu/hr/unit	0.0088 lb/MMBtu
Brunswick County Power	Freeman, VA	03/12/2013	3 Mitsubishi M501 GAC with DF Combined GT and DF 3442 MMBtu/hr/unit	9.7 lb/hr/unit and 0.0033 lb/MMBtu without DF 16.3 lb/hr and 0.0047 lb/MMBtu with DF
Moxie Patriot LLC	Clinton Twp, PA	01/31/2013	Equipment type not specified 2 - 472 or 458 MW combined cycle blocks with DF	0.0057 lb/MMBtu
Garrison Energy Center	Dover, DE	01/30/2013	GE 7FA 309 MW	32.1 lb/hr
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	4 - “F Class” (GE or Siemens) 1345 MW total	15 lb/hr/unit and 0.0092 lb/MMBtu without DF 18 lb/hr and 0.0078 lb/MMBtu with DF
Hess Newark Energy	Newark, NJ	11/01/2012	2 - GE 7FA.05 2320 MMBtu/hr/unit plus 211 MMBtu/hr DF	11 lb/hr/unit without DF 13.2 lb/hr with DF
Channel Energy Center, LLC	Houston, TX	10/15/2012	2 - Siemens 501F 180 MW plus 425 MMBtu/hr DF	27.0 lb/hr

Table 1-1. Summary of Recent Particulate PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] PM/PM_{10}/$PM_{2.5}$
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	Siemens "H Class" 2 – 468 or less MW combined cycle blocks GT $\leq$ 2890 MMBtu/hr/unit DF $\leq$ 3870 MMBtu/hr/unit	0.0057 lb/MMBtu for 454 MW block 0.0040 lb/MMBtu for 468 MW block
Cricket Valley	Dover, NY	09/27/2012	3 - GE 7FA.05 2061 MMBtu/hr/unit plus 379 MMBtu/hr DF	0.005 lb/MMBtu without DF 0.006 lb/MMBtu with DF
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	1 - Siemens 501F 180 MW plus 725 MMBtu/hr DF	27.0 lb/hr
ES Joslin Power	Calhoun, TX	09/12/2012	3 - GE 7FA 195 MW per unit No DF	18.0 lb/hr
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	1 Mitsubishi M501GAC 2542 MMBtu/hr/unit; no DF	9.8 lb/hr 0.004 lb/MMBtu
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	2 GE 7FA 154 MW (1736 MMBtu/hr) per unit plus 500 MMBtu/hr DF	8.46 lb/hr/unit and 0.0048 lb/MMBtu without DF 11.3 lb/hr and 0.0049 lb/MMBtu with DF
Thomas C. Ferguson Power	Llano, TX	09/01/2011	2 - GE 7FA 195 MW per unit No DF	18.0 lb/hr
Entergy Ninemile Point Unit 6	Westwego, LA	08/16/2011	Vendor not specified Single unit 550MW	26.23 lb/hr/unit without DF 33.16 lb/hr with DF
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	1 Siemens SGT6-PAC-5000F 2227 MMBtu/hr plus 641 MMBtu/hr DF	17.4 lb/hr 0.007 lb/MMBtu
Avenal Power Center	Avenal, CA	05/27/2011	2 - GE 7FA 1856.3 MMBtu/hr/unit plus 562.26 MMBtu/hr DF	8.91 lb/hr/unit without DF 11.78 lb/hr with DF
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	1 - Mitsubishi M501GAC 2866 MMBtu/hr	0.0083 lb/MMBtu
Dominion Warren County	Front Royal, VA	12/21/2010	3 -Mitsubishi M501 GAC 2996 MMBtu/hr/unit plus 500 MMBtu/hr DF	8.0 lb/hr/unit and 0.0027 lb/MMBtu without DF 14.0 lb/hr and 0.0040 lb/MMBtu with DF
Pondera/King Power Station	Houston, TX	08/05/2010	4 GE 7FA.05 2430 MMBtu/hr/unit GT plus DF or 4 Siemens SGT6-5000F5 2693 MMBtu/hr/unit GT plus DF	GE: 19.80 lb/hr/unit (w/ and w/o DF) Siemens: 11.1 lb/hr/unit (w/ and w/o DF)
Live Oaks Power	Sterling, GA	03/30/2010	Siemens SGT6-5000F	No emission limits specified. PSD BACT for PM_{10}/$PM_{2.5}$ use of pipeline quality natural gas
Victorville 2 Hybrid	Victorville, CA	03/11/2010	2 GE 7FA 154 MW per unit plus 424.3 MMBtu/hr DF	12.0 lb/hr/unit without DF 18.0 lb/hr with DF

Table 1-1. Summary of Recent Particulate PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] PM/PM_{10}/$PM_{2.5}$
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	2 GE 7FA 170 MW/unit plus 570 MMBtu/hr DF or 2 Mitsubishi M501G 254 MW/unit plus 230 MMBtu/hr DF	GE: 12.0 lb/hr/unit (w/ and w/o DF) Mitsubishi: 20.0 lb/hr/unit (w/ and w/o DF)
Panda Sherman Power	Grayson, TX	02/03/2010	2 GE 7FA or 2 Siemens SGT6-5000F with 468 MMBtu/hr/unit DF	GE: 12.0 lb/hr/unit (without DF) 27.0 lb/hr with DF Siemens: 11.0 lb/hr/unit without DF 15.4 lb/hr with DF
Russell City Energy Center	Hayward, CA	02/03/2010	2 - Siemens 501F 2238.6 MMBtu/hr/unit plus 200 MMBtu/hr DF	7.5 lb/hr/unit 0.0036 lb/MMBtu
Lamar Power Partners II LLC	Paris, TX	06/22/2009	4 - GE 7FA with 200 MMBtu/hr DF	18.0 lb/hr/unit without DF 20.3 lb/hr with DF
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	4 – GE 7FA, GE7FB, or Siemens SGT6-5000F With DF	20.8 lb/hr/unit (each option)
Entergy Lewis Creek Plant	The Woodlands, TX	05/19/2009	2 - GE 7FA with 362 MMBtu/hr DF	27.14 lb/hr/unit

[1] DF refers to duct firing
[2] Includes front (filterable) and back-half (condensable) PM. Limits obtained from agency permitting documents when not available in RBLC. Short-term emission limits only are provided.

GE has historically guaranteed particulate emissions on constant lb/hr basis, regardless of turbine load. Thus, as shown in Table 1-1, many of the GE turbines have PSD BACT limits expressed strictly in lb/hr.

Footprint has calculated lb/MMBtu values inclusive of minimum emission compliance load (MECL). (Note that duct-firing will not occur at MECL, so the MECL-based limit is only for unfired conditions). Footprint has determined that the flexibility to operate at MECL is important to the Project's mission of providing a flexible and quick response to the future system power needs. Footprint's draft PSD permit and Plan Approval also require $PM/PM_{10}/PM_{2.5}$ emission testing at MECL. MECL turbine operation therefore results in Footprint's highest lb/MMBtu rate of 0.0071 lb/MMBtu. It is important to note that a number of the lb/MMBtu emission rates in Table 1-1 correspond to (just) the full load heat input rate. For comparative purposes, the Footprint full load lb/MMBtu/hr $PM/PM_{10}/PM_{2.5}$ emission rate (without duct firing) ranges from 0.0038 to 0.0047 lb/MMBtu.

Table 1-1 lists 34 projects with PSD BACT limits for $PM/PM_{10}/PM_{2.5}$ approved in the last 5 years. Over half of these projects (18) clearly have $PM/PM_{10}/PM_{2.5}$ limits less stringent than the Footprint limits discussed above. Of the remaining 16 projects, most of these are for turbine suppliers other than GE, and generally have lower $PM/PM_{10}/PM_{2.5}$ limits expressed on a lb/MMBtu basis. The lb/MMBtu comparison allows $PM/PM_{10}/PM_{2.5}$ rates for projects of different sizes to be more readily compared. The most stringent lb/MMBtu limit identified is for the Dominion Warren County (VA) project, which is 0.0027 lb/MMBtu without duct firing. The Dominion Warren County project is based on 3 Mitsubishi 501GAC turbines. Mitsubishi in particular has recently taken a more aggressive approach to $PM/PM_{10}/PM_{2.5}$ guarantees, as reflected by the Warren County Project as well as the Brunswick County (VA) project (0.0033 lb/MMBtu without duct firing and 0.0047 lb/MMBtu with duct firing), the Oregon (Ohio) project (0.00384 lb/MMBtu without duct firing and 0.00373 lb/MMBtu with duct firing) and PVEC (0.004 lb/MMBtu without duct firing as noted in the CLF comment letter to MassDEP on the Footprint project).

With respect to the $PM/PM_{10}/PM_{2.5}$ limits achievable for the Mitsubishi 501GAC turbine, it is significant to note that an email from George Pyros of Mitsubishi Power Systems dated October 7, 2013, which was submitted to MassDEP in comments concerning Footprint Power, indicates that Mitsubishi has "not yet conducted stack PM emissions testing for our M501GAC gas turbine in combined cycle. However, we have M501GAC units that will be commissioned next year in combined cycle that will provide such data." (The Mitsubishi 501GAC project that is closest to commissioning is the Dominion Warren County project.) The email from Mitsubishi actually supports Footprint's position, as provided in supplemental material submitted to MassDEP on August 20, 2013, insofar as the fact that ultra-low particulate rates for the 501GAC turbine are not demonstrated in practice. In the August 20, 2013 submission, Footprint questioned whether the 0.004 lb/MMBtu emission rate for the PVEC was achievable in practice. This is based on the fact that four Mitsubishi 501G units at Mystic Station (Everett MA), had tested PM emissions (in 2003) ranging from 0.005 – 0.010 lb/MMBtu. While the 501GAC turbine has a newer generation combustion system, the majority of the tested particulate matter at Mystic was condensable particulates. It is not at all clear how a newer generation combustion system would achieve better control of condensable particles. While careful adherence to particulate testing procedures can minimize testing variably and artifact condensable emissions, Footprint remains convinced that the Mitsubishi's recent 501GAC limits, particularly those for the Warren County project, present undue project risk.

In addition, for Mitsubishi and Siemens projects with $PM/PM_{10}/PM_{2.5}$ lb/MMBtu limits, these limits appear to be approved as constant across the operating load range. This represents a different guarantee philosophy than used by GE. Again, Footprint believes this is a guarantee philosophy difference and does not reflect actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions due to the type of turbine. As noted in Footprint's comment letter to MassDEP dated November 1, 2013, at full load unfired conditions, Footprint's lb/MMBtu rates for $PM/PM_{10}/PM_{2.5}$ range from 0.0038 to 0.0047 lb/MMBtu. These full load rates compare favorably to many of the lb/MMBtu rates for Siemens and Mitsubishi in Table 1-1.

Several Siemens "F Class" $PM/PM_{10}/PM_{2.5}$ limits in Table 1-1 (Renaissance, Langley Gulch, Pondera King) have lb/hr limits higher than the Footprint unfired value of 8.8 lb/hr, but do not incorporate higher duct firing limits (as is typically found to be necessary by available duct burner guarantees). Again, Footprint believes this is a guarantee philosophy difference and does not reflect actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions due to the type of turbine and whether duct firing is present or not.

The Russell City Energy Center Project is based on 2 Siemens 501F turbines, and was approved with $PM/PM_{10}/PM_{2.5}$ limits of 7.5 lb/hr and 0.0038 lb/MMBtu. Again, Footprint believes this is a guarantee philosophy difference and does not reflect actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions. However, one item of particular note in the Russell City Energy Center PSD Permit is that the permit allows the facility to propose alternate measuring techniques to measure condensable PM, such as the use of a dilution tunnel. A dilution tunnel is expected to result in lower (and more realistic) tested emissions compared to typical stationary source impinger techniques for measuring condensable PM. Therefore, this permit provision may explain in part the rationale for the Russell City Energy Center strategy for accepting lower permit limits. Dilution tunnel based measurements for condensable PM are expected to more accurately simulate the process by which condensable PM forms compared to impinger techniques, which still present concerns with artifact emissions.

There is one other GE 7FA unit noted in Table 1-1 that has $PM/PM_{10}/PM_{2.5}$ limits of comparative note. This is the Green Energy (VA) project. This project is approved for either GE 7FA or Siemens turbines. For GE 7FA, the lb/hr limits are less stringent than Footprint but the lb/MMBtu limits are more stringent. The Green Energy lb/MMBtu limits appear to be incorrectly calculated (too low), even based on the full load firing rates.

In summary, the available evidence clearly indicates that PSD BACT for $PM/PM_{10}/PM_{2.5}$ emissions is to use of state of the art combustion turbines, with good combustion practices and the use of natural gas. The actual guarantees for $PM/PM_{10}/PM_{2.5}$ emissions vary by manufacturer, and permit limits within the range of recently approved projects for a given turbine supplier are justified as PSD BACT limits.

1.1.4 PSD Best Available Control Technology Assessment for Sulfuric Acid Mist (H_2SO_4)

Emissions of H_2SO_4 from natural gas-fired combined cycle units result from oxidation of trace quantities of sulfur in natural gas. Normally, fuel sulfur oxidizes to SO_2. A generally small portion of fuel sulfur may initially oxidize directly to SO_3 rather than SO_2. Also, a portion of the fuel sulfur which initially oxidizes to SO_2 may subsequently oxidize to SO_3 prior to being emitted. For purposes of emission calculations, all SO_3 is assumed to combine with water vapor in the flue gas to form H_2SO_4.

For H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for H_2SO_4 is limiting the fuel sulfur content. Based on the selection of natural gas as the BACT fuel, this is the lowest sulfur content fuel available.

Key considerations in the development of a specific H_2SO_4 emission rate for a natural gas-fired combined cycle unit are the sulfur content of natural gas, and the appropriate allowance for oxidation of fuel sulfur and SO_2 to SO_3. For the sulfur content of natural gas, the Project has used the EPA definition of "pipeline natural gas" in 40 CFR 72.2. This definition is that pipeline natural gas has a maximum sulfur content of 0.5 grains of sulfur per 100 standard cubic feet (scf). Based on data from GE, up to 5% of the fuel sulfur is expected to convert directly to SO_3 in the turbine combustor/duct burners. Then, up to 35% of the (remaining) SO_2 is expected to convert to SO_3 in passing through the oxidation catalyst, and up to an additional 5% of the (remaining) SO_2 is expected to convert to SO_3 in passing through the SCR system. As documented in the Project supplemental data submitted to MassDEP on August 20, 2013, the resulting

H_2SO_4 emission rate is 0.0010 lb/MMBtu. This corresponds to a maximum emission rate of 2.3 lb/hr of H_2SO_4 per unit.

Pursuant to identifying candidate control technologies under the "top-down" procedure, the Applicant has compiled all the PSD BACT determinations for H_2SO_4 in the last five years for new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. This review confirms that the only H_2SO_4 BACT technology identified for large natural gas fired combined cycle turbines is use of clean fuel (i.e., natural gas). There are no cases where any post combustion controls have been used to control H_2SO_4 emissions from large natural gas fired combined cycle turbines. Therefore, the PSD BACT analysis for H_2SO_4 does not require any evaluation of alternative control technologies.

The "top-down" procedure does require selection of BACT emission limits. Table 1-2 presents the results of RBLC compilation for H_2SO_4. As for $PM/PM_{10}/PM_{2.5}$, BACT emissions for H_2SO_4 can be expressed either as lb/MMBtu or lb/hr, or both. Table 1-2 lists 22 projects with PSD BACT limits for H_2SO_4 approved in the last 5 years. More than half of these projects (13) have H_2SO_4 limits equal or less stringent than the Footprint limits discussed above. Of the remaining 9 projects, the lower H_2SO_4 rates appear to be due to either unrealistically low assumptions on SO_2 to SO_3 oxidation, low assumed natural gas sulfur contents, or both. One of the projects listed in Table 1-2 (Panda Sherman) was approved without a CO oxidation catalyst, which explains the low H_2SO_4 rate for this project. As noted above, a CO oxidation catalyst oxidizes some of the SO_2 to SO_3/H_2SO_4. However, the other projects in Table 1-2 with lower H_2SO_4 rates appear to have assumed a very stringent natural gas sulfur content and/or did not take into account the unavoidable incremental oxidation of SO_2 to SO_3 from a CO catalyst. Footprint does not believe it is prudent to ignore the SO_2 to SO_3 oxidation from a CO catalyst, or assume a natural gas sulfur content lower than EPA's definition for "pipeline natural gas" (0.5 grains of S/100 scf).

In summary, the available evidence clearly indicates that PSD BACT for H_2SO_4 for combustion turbines is use of clean low sulfur fuel (e.g., natural gas). The H_2SO_4 emission calculation needs to allow for a reasonable variation in the sulfur content of pipeline natural gas, which is outside the control of a given generation facility, and oxidation of SO_2 to SO_3 oxidation from a CO catalyst. The Applicant proposes a H_2SO_4 limit for the Project (0.0010 lb/MMBtu), which is consistent with recent PSD BACT precedents which properly account for these variables.

Table 1-2. Summary Of Recent H_2SO_4 PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] Sulfuric Acid Mist (H_2SO_4)
Carroll County Energy	Washington Twp., OH	11/5/2013	2 GE 7FA 2045 MMBtu/hr/unit plus 566 MMBtu/hr DF	0.0012 lb/MMBtu without DF 0.0016 lb/MMBtu with DF
Oregon Clean Energy	Oregon, OH	06/18/2013	2 Mitsubishi M501GAC or 2 Siemens SCC6-8000H 2932 MMBtu/hr/unit plus 300 MMBtu/hr DF	Mitsubishi: 0.00041 lb/MMBtu without DF Mitsubishi: 0.00044 lb/MMBtu with DF Siemens: 0.0006 lb/MMBtu without DF Siemens: 0.0007 lb/MMBtu with DF
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	GE7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H. 2 combined cycle units	0.92 lb/hr/unit without DF 1.08 lb/hr/unit with DF Emissions based on Siemens SGT6-8000H
Sunbury Generation	Sunbury, PA	04/01/2013	"F Class" with DF 2538 MMBtu/hr/unit	0.0018 lb/MMBtu 4.4 lb/hr/unit without DF 4.7 lb/hr/unit with DF
Brunswick County Power	Freeman, VA	03/12/2013	3 Mitsubishi M501 GAC with DF Combined GT and DF 3442 MMBtu/hr/unit	0.00058 lb/MMBtu without DF 0.00067 lb/MMBtu with DF
Moxie Patriot LLC	Clinton Twp, PA	01/31/2013	Equipment type not specified 2 - 472 or 458 MW combined cycle blocks with DF	0.0005 lb/MMBtu
Garrison Energy Center	Dover, DE	01/30/2013	GE 7FA 309 MW	6.5 lb/hr
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	4 - "F Class" (GE or Siemens) 1345 MW total	0.75 grains S/100 scf of natural gas
Hess Newark Energy	Newark, NJ	11/01/2012	2 - GE 7FA.05 2320 MMBtu/hr/unit plus 211 MMBtu/hr DF	1.36 lb/hr/unit without DF 1.33 lb/hr/unit with DF
Channel Energy Center, LLC	Houston, TX	10/15/2012	2 - Siemens 501F 180 MW plus 425 MMBtu/hr DF	4.8 lb/hr/unit
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	Equipment type not specified 2 – 468 or less MW combined cycle blocks GT $\leq$ 2890 MMBtu/hr/unit DF $\leq$ 3870 MMBtu/hr/unit	0.0002 lb/MMBtu 1.4 lb/hr for 454 MW block 1.5lb/hr for 468 MW block
Cricket Valley	Dover, NY	09/27/2012	3 - GE 7FA.05 2061 MMBtu/hr/unit plus 379 MMBtu/hr DF	0.5 grains S/100 scf of natural gas
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	1 - Siemens 501F 180 MW plus 725 MMBtu/hr DF	4.89 lb/hr/unit
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	1 Mitsubishi M501GAC 2542 MMBtu/hr/unit; no DF	0.0018 lb/MMBtu 3.6 lb/hr
Thomas C. Ferguson Power	Llano, TX	09/01/2011	2 - GE 7FA 195 MW per unit No DF	13.68 lb/hr

Table 1-2. Summary Of Recent H_2SO_4 PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] Sulfuric Acid Mist (H_2SO_4)
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	1 - Mitsubishi M501GAC 2866 MMBtu/hr	1.5 lb/MMcf (0.0015 lb/MMBtu)
Dominion Warren County	Front Royal, VA	12/21/2010	3 -Mitsubishi M501 GAC 2996 MMBtu/hr/unit plus 500 MMBtu/hr DF	0.00013 lb/MMBtu without DF 0.00025 lb/MMBtu with DF
Pondera/King Power Station	Houston, TX	08/05/2010	4 GE 7FA.05 2430 MMBtu/hr/unit GT plus DF or 4 Siemens SGT6-5000F5 2693 MMBtu/hr/unit GT plus DF	GE: 3.37 lb/hr/unit (w/ and w/o DF) Siemens: 3.77 lb/hr/unit (w/ and w/o DF)
Live Oaks Power	Sterling, GA	03/30/2010	Siemens SGT6-5000F	No emission limits specified. PSD BACT for H_2SO_4 use of pipeline quality natural gas with $\leq$ 0.5 grains S/100 scf
Panda Sherman Power	Grayson, TX	02/03/2010	2 GE 7FA 170 MW/unit plus 570 MMBtu/hr DF or 2 Mitsubishi M501G 254 MW/unit plus 230 MMBtu/hr DF	GE: 0.56 lb/hr/unit (w/ and w/o DF) Mitsubishi: 0.62 lb/hr/unit (w/ and w/o DF)
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	4 – GE 7FA, GE7FB, or Siemens SGT6-5000F With DF	GE: 1.9 lb/hr/unit (w/ and w/o DF) Mitsubishi: 2.0 lb/hr/unit (w/ and w/o DF)
Entergy Lewis Creek Plant	The Woodlands, TX	05/19/2009	2 - GE 7FA with 362 MMBtu/hr DF	4.03 lb/hr/unit

[1] DF refers to duct firing
[2] Limits obtained from agency permitting documents when not available in RBLC. Short-term emission limits only are provided.

1.1.5 Best Available Control Technology Assessment for Greenhouse Gases

Step 1: Identify Potentially Feasible GHG Control Options

In Step 1, the applicant must identify all "available" control options which have the potential for practical application to the emission unit and regulated pollutant under evaluation, including lower-emitting process and practices. In assessing available GHG control measures, we reviewed EPA's RACT/BACT/LAER Clearinghouse, the South Coast Air Quality Management District's BACT determinations, and the Pioneer Valley Energy Center permit information found on the EPA Region 1 website (Pioneer Valley is a recently permitted 431 MW combined cycle turbine project in Westfield, Massachusetts). EPA stated generally that BACT for the Pioneer Valley project is energy efficient combustion technology and additional energy savings measures at the facility, if possible. Specifically, BACT was cited as installation of a combined cycle turbine and GHG emission limits were developed.

For the proposed Project, potential GHG controls are:

1. Low carbon-emitting fuels;
2. Carbon capture and storage (CCS); and
3. Energy efficiency and heat rate.

Step 2: Technical Feasibility of Potential GHG Control Options

<u>Low Carbon-Emitting Fuels</u>

Natural gas combustion generates significantly lower carbon dioxide emission rates per unit heat than distillate oil (approximately 27% less) or coal (approximately 50% less). Use of biofuels would reduce fossil-based carbon dioxide emissions, since biofuels are produced from recently harvested plant material rather than ancient plant material that has transformed into fossil fuel. However, biofuels are in liquid form, and the Project is not being designed for liquid fuel. In addition, combined cycle turbines have technical issues with biofuels that have yet to be resolved. It is likely that distillate fuel would need to have a limited percentage of biofuel added to be feasible. In this case, natural gas would still have lower fossil-based carbon emissions compared a distillate oil/biofuel mixture. For these reasons, biofuels have been eliminated from consideration. Therefore, natural gas represents the lowest carbon fuel available for the Project.

<u>Energy Efficiency and Heat Rate</u>

EPA's GHG permitting guidance states,

> "Evaluation of [energy efficiency options] need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of [a] new facility as a whole (e.g., installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reductions achieved. EPA instead recommends that the BACT analyses for units at a new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (e.g., induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions...."

EPA also recommends that permit applicants "propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks...which represent a high level of performance within an industry." With regard to electric generation from combustion sources, the combined cycle combustion turbine is considered to be the most efficient technology available. Below is a discussion of energy efficiency and a comparison to other common combustion-based electric generation technologies.

GHG emissions from electricity production are primarily a function of the amount of fuel burned; therefore, a key factor in minimizing GHG emissions is to maximize the efficiency of electricity production. Another way to refer to maximizing efficiency is minimizing the heat rate. The heat rate of an electric generating unit is the amount of heat needed in BTU (British Thermal Units) to generate a kilowatt of electricity (kW), usually reported in Btu/kW-hr. The more efficient generating units have lower heat rates than less efficient units. Older, more inefficient boilers and turbines consume more fuel to generate the same amount of electricity than newer, more efficient boilers and turbines. This is due to equipment wear and tear, improved design in newer models as well as the use of higher quality metallurgy. In general, a boiler-based steam electric unit is less efficient than a combustion turbine combined cycle unit. This is because the combustion energy from a combustion turbine is directly imparted onto the turbine blades, and a combined cycle unit then uses the waste heat from the combustion turbine exhaust to generate additional power, utilizing a HRSG and subsequent steam cycle.

In addition to the efficiency of the electricity generation cycle itself, there are a number of key plant internal energy sinks (parasitic losses) that can improve a plant's net heat rate (efficiency) if reduced. Measures to increase energy efficiency are clearly technically feasible and are addressed in more detail in Step 4 of the BACT process.

Carbon Capture and Storage

With regard to CCS, as identified by US EPA, CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options). While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases.

As identified by the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage (co-chaired by US EPA and the US Department of Energy), while amine- or ammonia-based CO_2 capture technologies are commercially available, they have been implemented either in non-combustion applications (i.e., separating CO_2 from field natural gas) or on relatively small-scale combustion applications (e.g., slip streams from power plants, with volumes on the order of what would correspond to one megawatt). Scaling up these existing processes represents a significant technical challenge and potential barrier to widespread commercial deployment in the near term. It is unclear how transferable the experience with natural gas processing is to separation of power plant flue gases, given the significant differences in the chemical make-up of the two gas streams. In addition, integration of these technologies with the power cycle at generating plants present significant cost and operating issues that will need to be addressed to facility widespread, cost-effective deployment of CO_2 capture. Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant applications.

Regarding pipeline transport for CCS, there is no nearby existing CO_2 pipeline infrastructure (see Figure 1-1); the nearest CO_2 pipelines to Massachusetts are in northern Michigan and southern Mississippi. With regard to storage for CCS, the Interagency Task Force concluded that while there is currently estimated to be a large volume of potential storage sites, "to enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes" and that "scale-up from a limited number of demonstration projects to widescale commercial deployment may necessitate the consideration of basin-scale factors (e.g., brine displacement, overlap of pressure fronts, spatial variation in depositional environments, etc.)".

Based on the abovementioned EPA guidance regarding technical feasibility and the conclusions of the Interagency Task Force for the CO_2 capture component alone (let alone a detailed evaluation of the technical feasibility of right-of-ways to build a pipeline or of storage sites), CCS has been determined to not be technically feasible.

Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

Based on the results of Step 2, the only option being carried further into the analysis is the evaluation energy efficiency and heat rate. The Project is already using the lowest carbon fuel and carbon capture and storage is not currently feasible.

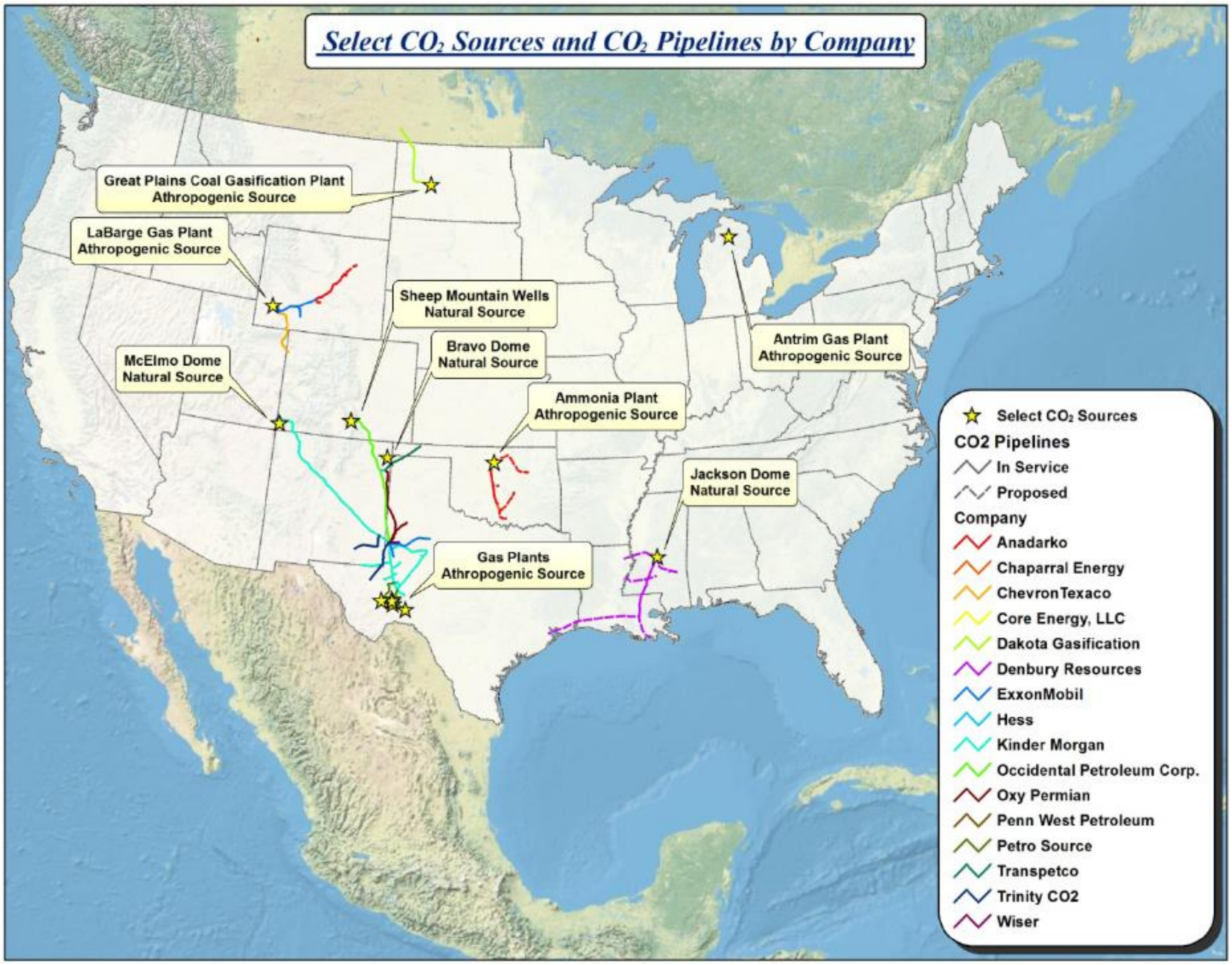
Step 4: Evaluation of Energy Efficiency and Heat Rate

Improvements to energy efficiency and "heat rate" are important GHG control measures that can be employed to mitigate GHG emissions. Heat rate indicates how efficiently power is generated by combustion of a given amount of fuel. Heat rate is normally expressed in units of British thermal units (Btu) combusted per net kilowatt-hour (kw-hr) of energy produced. A higher value of "heat rate" indicates more fuel (i.e., Btu) is needed to produce a given amount of energy (lower or less favorable efficiency), while a lower value of heat rate indicates less fuel (i.e., Btu) is needed to produce a given amount of energy (higher or more favorable efficiency).

The Proposed Project is using advanced combustion turbine combined cycle technology, which is recognized as the most efficient commercially available technology for producing electric power from fossil fuels. Improvements to the heat rate typically will not change the amount of fuel combusted for a given combustion turbine installation, but it will allow more power to be produced from a given amount of fuel (i.e., improve the heat rate) so that more GHG emissions will be displaced from existing sources.

Key factors addressed in the evaluation of energy efficiency and heat rate are the core efficiency of the selected turbines and the significant factors affecting overall net heat rate in combined cycle operating mode.

Figure 1-1. CO_2 Pipelines in the United States



From: "Report of the Interagency Task Force on Carbon Capture and Storage," August 2010, Appendix B.

The design basis of the proposed project is to install approximately 630 MW of electric, generation which is equivalent to two "F" Class turbines in combined cycle configuration. "G" class turbines are slightly more efficient and thus have a lower heat rate; however, "G" class turbines generate approximately 380 to 400 MW per turbine (or 760 to 800 MW for two turbines). In addition, "G" class turbines generally have a higher low operating limit (the lowest MW output at which the facility can operate in compliance with its permits) than the proposed "F" class turbines. Although "G" class turbines are slightly more energy efficient that the proposed "F" Class turbines, "G" Class turbines would alter the scope of the project due to their size. The "F" Class design size provides the compatible size match to the existing high voltage switchyard and electrical interconnection infrastructure associated with the exiting Salem Harbor Generating Station site. The "F" class design also provides greater operational flexibility and therefore lower overall emissions. The expected heat rate or efficiency differential between "F" and "G" combined cycles, comparably configured and equipped is less than 1 percent at ISO conditions, in unfired mode, when both plants are comparably equipped for quick start-up. When site specific conditions are accounted for, this apparent efficiency difference between "F" and "G" class machines is further reduced by the higher parasitic power consumption of the fuel gas compressors for the "G" machines, which require higher natural gas supply pressures compared to “F” class. For these reasons, “G” class machines have been eliminated from consideration for the Proposed Project.

The advanced generation of “F” class machines have upgraded performance with increased MW output and improved heat rate compared to prior designs. These machines also represent the current state-of-the-art for the evolving “F” class technology that is now been in operation for greater than 20 years with thousands of machines in operation. This provides a conservative and predictable basis to formulate financial plans and to project future reliability and costs. The steam cycle portion of the plant (HRSG, piping, & steam turbine generator) as designed with two smaller units in the “1 on 1” configuration will exhibit superior operational flexibility, ability to deal with rapid thermal transients and exhibit acceptable and foreseeable long term O&M cost impacts.

With regard to energy efficiency considerations in combined cycle combustion turbine facilities, the activity with the greatest effect on overall efficiency is the method of condenser cooling. As with all steam-based electric generation, combined cycle plants can use either dry cooling or wet cooling for condenser cooling. Dry cooling uses large fans to condense steam directly inside a series of piping, similar in concept to the radiator of a car. Wet cooling can either be closed cycle evaporative cooling (using cooling towers), or “once-through” cooling using sea water.

Total fuel heat input to the combined cycle combustion turbine (fuel burned in the combustion turbines and in the HRSG duct burners) and thus total steam flow available to the steam turbine, is fixed. The efficiency of conversion of the fixed steam flow to electrical output of the steam turbine generator is then primarily a function of the backpressure at which the low pressure turbine exhausts. A wet cooling system consisting either of a mechanical draft cooling tower with circulating water pumps and a shell and tube condenser, or a once-through system directly circulating sea water to the condenser, are capable of providing significantly lower condensing pressures compared to an all dry ACC system. Wet cooling performance is superior for efficiency purposes because of the basic thermodynamics of cooling, which allows either the cooling tower or once through system to produce colder water compared to dry cooling. As a result, operation of a dry cooling system requires approximately 1-5% more energy than a wet cooling system depending on ambient conditions (difference between wet and ACC systems gets smaller with lower ambient temperatures).

However, there are significant drawbacks to either a once-through system or wet mechanical draft cooling tower system. Once-through cooling involves use of large quantities of sea water that is returned to the ocean at a higher temperature. The impingement and entrainment associated with intake of the necessary large quantities of sea water, and the thermal impacts of discharges of once-through cooling, have been recognized to have negative environmental impacts and once-through cooling has therefore been eliminated from consideration.

Wet mechanical draft cooling towers also require a significant quantity of water, most of which is lost to evaporation to the atmosphere. Seawater can potentially be used for makeup to a wet evaporative system, but this is is a very challenging application. The most likely candidate source for the volumes of cooling tower makeup water required would be the SESD sewage treatment plant. It is technically feasible to use effluent from a public sewerage treatment facility as make-up to a wet, evaporative cooling system. However the presence of typical chemical constituents in the effluent and the likely highly variable concentrations of certain of these constituents would place a burden on the Project. The effluent transferred from SESD would require further treatment to make it suitable and safe to use in the cooling system. Even after further treatment the concentrations of certain dissolved minerals in the circulating water would impact the design; most likely require a high degree of cooling tower blowdown to maintain acceptable chemistry and requiring the upgrade of the metallurgy of the piping, condenser tube, pumps and other components that would be exposed to the more corrosive action of the treated and concentrate effluent.

An additional burden imposed of wet, evaporative cooling is dealing with the creation of visible fog plume, which discharges from the cooling tower fans. With the typical New England, coastal site weather conditions, a standard mechanical draft cooling tower would produce a very visible and persistent plume for many hours of the year. It is possible to use a so-called “plume abated” mechanical draft tower. But this feature can double the cost of the cooling tower and increase the total fan power consumption and pumping head on the system. Basically the “plume abatement” feature works by using heat from the hot condenser discharge water to preheat additional ambient air admitted above the normal cooling tower wet, evaporative heat exchange zone. This hotter air has a lower relative humidity; such that as it mixes with the wet, almost saturated air discharged from the evaporative cooling surface, the combined air mixture reaches a moisture content below the saturation point. As this hotter, dryer air mixture is discharged by the tower fans it can then mix with the cool, damp ambient air without crossing the saturation line and producing small water droplets which form the visible plume.

The bottom line is that a wet, evaporative mechanical draft cooling tower with plume abatement features has a doubled capital cost, higher fan power consumption and higher pumping head than a standard cooling tower. These latter two factors greatly reduce any potential benefit from reduced parasitic load from the wet cooling system.

Therefore, Footprint has determined that the marginal heat rate improvement that could be achieved with a plume abated mechanical draft tower does not outweigh the drawback of the technical issue associated with use of the SESD sewage effluent, as well as the fact that a visible plume will still be present at times with a plume abated tower. The use of dry cooling has therefore been selected over either wet cooling option.

The Administration Building has been designed to meet the U.S. Green Building Council’s Leadership in Energy and Environmental Design (LEED) at the Platinum level. The Administration Building, as well as the Operations Building, among various energy conservation features, incorporate green roofs, geothermal heat pumps for heating and cooling, building energy management systems, and a 10% reduction in lighting power density.

Step 5: Select BACT

The Project has proposed GHG limits as follows for the combined cycle units:

- Initial test limit of 825 lb CO_2e/MWhr (net to grid), full load, ISO corrected, without duct firing
- Rolling 365-day GHG BACT limit (life of facility) of 895 lb CO_2e/MWhr (net to grid)

For purposes of comparison, the initial test GHG limit of 825 lb CO_2e/MWhr (net to grid) corresponds to a “heat rate” of 6,940 Btu HHV/kWhr (net). On a “gross” energy basis, these values are 795 lb CO_2e/MWhr (gross) and 6,688 Btu HHV/kWhr (gross). The rolling 365-day GHG BACT limit of 895 lb CO_2e/MWhr (net to grid) corresponds to a “heat rate” of 7,521 Btu HHV/kWhr (net). On a “gross” energy basis, these values are 862 lb CO_2e/MWhr (gross) and 7,247 Btu HHV/kWhr (gross).

Note that “gross” energy is based on the full electric energy output of the generation equipment, without consideration of internal plant loads (parasitic losses such as for pumps and fans). Net energy is based on the amount of electric energy after internal plant demand is satisfied, and reflects the amount of energy actually sold to the electric grid.

For purposes of comparison with other projects, Footprint's design thermal efficiency is 57.9%. This is based on ISO full load operation, without duct firing or evaporative cooling, without any degradation allowance, and reflects gross energy output fuel energy input based on LHV. This is the most typical way that thermal efficiency is reported. This is not as meaningful for purposes of GHG BACT limits compared to measures based on net power production, since those based on net power account for the project internal energy consumption. Footprint considers the proposed rolling 12-month CO_2e limit for the life of the project as the most meaningful limit since it reflects actual long-term emissions, and actual power delivered to the grid.

Pursuant to supporting these proposed limits consistent with the "top-down" procedure, Footprint has compiled PSD BACT determinations for GHG in the last five years for new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on all entries during this time period listed in the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. This review confirms that the only BACT technology identified for large natural gas fired combined cycle turbines is use of low carbon fuel (i.e., natural gas) in high efficiency combined cycle units. There are no cases where any post combustion controls (carbon capture and sequestration) have been used to control GHG emissions from large natural gas fired combined cycle turbines.

Table 1-3 presents the results of RBLC compilation for GHG. GHG BACT emissions are expressed in varying units, including mass emission (tons or pounds per unit time), lb CO_2e per MWhr, and/or "heat rate" (Btu/kWhr). The energy-based limits are expressed as either "gross" or "net". Energy units (MWhr or kWhr) or more meaningful than mass emission limits since they relate directly to the efficiency of the equipment, which is a key available BACT technology (in addition to low carbon fuel). The mass emissions are specific to the fuel firing rate of a given project and the carbon content of the fuel, but do not incorporates the project efficiency.

Table 1-3 lists 15 projects with PSD BACT limits for GHG approved in the last 5 years which have energy based GHG limits. (The mass limit projects are not considered since they are not meaningful for GHG BACT comparison). Accounting for the different units for these limits, the Footprint Project proposed GHG limits are clearly more stringent than most of the energy based limits in Table 1-3. For limits where this comparison is not clear, the following clarifications are made:

- The basis for Oregon (OH) Clean Energy project limits (840 and 833 lb/MWhr gross) is not clear, but the context of this actual permit suggests these limits are intended for ISO conditions without duct firing which makes them less stringent than the Footprint limits.
- The Brunswick County limit of 7,500 Btu/kWhr net *at full load* with duct firing does not directly correspond to either of the Footprint conditions. However, Footprint's limit of 895 lb CO_2e/MWhr corresponds to a rolling 365-day value of 7,521 Btu/kWhr net which accounts for all operation on an annual basis including starts, stops, and part load in addition to duct firing.
- The Palmdale project limits of 774 lb/MWhr and 7,319 Btu/kWhr (source wide net 365 day average limits) are more stringent than the Footprint limits. However, the Palmdale project is a

Table 1-3. Summary Of Recent GHG PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] Greenhouse Gas (GHG) as CO2e unless otherwise noted
Carroll County Energy	Washington Twp., OH	11/5/2013	2 GE 7FA 2045 MMBtu/hr/unit plus 566 MMBtu/hr DF	859 lb/MWhr gross at ISO conditions without duct firing
Renaissance Power	Carson City, MI	11/1/2013	4 Siemens 501 FD2 units 2147 MMBtu/hr/unit each with 660 MMBtu/hr DF	1000 lb/MWhr gross 12-month rolling average
Oregon Clean Energy	Oregon, OH	06/18/2013	2 Mitsubishi M501GAC or 2 Siemens SCC6-8000H 2932 MMBtu/hr/unit plus 300 MMBtu/hr DF	Mitsubishi: 840 lb/MWhr gross Siemens: 833 lb/MWhr gross
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	2 GE 7FA.05 2230 MMBtu/hr/unit plus 650 MMBtu/hr DF or 2 Siemens SGT6-5000F5 2260 MMBtu/hr/unit plus 450 MMBtu/hr DF	Heat rate of 7,340 Btu HHV/kWhr gross without DF Heat rate of 7,780 HHV Btu/kWhr gross with DF
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	GE7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H. 2 combined cycle units	3,665,974 tpy both units Emissions based on Siemens SGT6-8000H
Sunbury Generation	Sunbury, PA	04/01/2013	"F Class" with DF 2538 MMBtu/hr/unit	281,727 lb/hr without DF 298,106 lb/hr with DF
Brunswick County Power	Freeman, VA	03/12/2013	3 Mitsubishi M501 GAC with DF Combined GT and DF 3442 MMBtu/hr/unit	Heat rate of 7,500 Btu(HHV)/kWhr net; tested at full load and corrected to ISO conditions with DF
Garrison Energy Center	Dover, DE	01/30/2013	GE 7FA with DF 309 MW	Heat rate of 7,717 Btu HHV/kWhr net 12-month rolling average
St. Joseph Energy center	New Carlisle, IN	12/03/2012	4 - "F Class" (GE or Siemens) 1345 MW total	Heat rate of 7,646 Btu/kWhr. Further detail not specified
Hess Newark Energy	Newark, NJ	11/01/2012	2 - GE 7FA.05 2320 MMBtu/hr/unit plus 211 MMBtu/hr DF	887 lb/MWhr gross 12-month rolling average Heat rate of 7,522 Btu(HHV)/kWhr; net basis at full load and corrected to ISO conditions without DF
Channel Energy Center, LLC	Houston, TX	10/15/2012	2 - Siemens 501F 180 MW plus 425 MMBtu/hr DF	920 lb/MWhr net
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	Equipment type not specified 2 – 468 or less MW combined cycle blocks GT $\leq$ 2890 MMBtu/hr/unit DF $\leq$ 3870 MMBtu/hr/unit	1,388,540 tpy for 454 MW block 1,480,086 tpy for 468 MW block
Cricket Valley	Dover, NY	09/27/2012	3 - GE 7FA.05 2061 MMBtu/hr/unit plus 379 MMBtu/hr DF	Heat rate of 7,605 Btu HHV/kWhr ISO without DF 57.4% design thermal efficiency 3,576,943 tpy all 3 units
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	1 - Siemens 501F 180 MW plus 725 MMBtu/hr DF	920 lb/MWhr net

Table 1-3. Summary Of Recent GHG PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] Greenhouse Gas (GHG) as CO2e unless otherwise noted
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	1 Mitsubishi M501GAC 2542 MMBtu/hr/unit; no DF	825 lb/MWhr net (initial full load test corrected to ISO conditions) 895 lb/MWhr net (rolling 365-day average)
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	2 GE 7FA 154 MW (1736 MMBtu/hr) per unit plus 500 MMBtu/hr DF	774 lb/MWhr source wide net 365 day rolling average (CO2) Heat rate: 7,319 Btu/kWhr source wide net 365 day rolling average
Thomas C. Ferguson Power	Llano, TX	09/01/2011	2 - GE 7FA 195 MW per unit No DF	908,957.6 lb/hr 30-day rolling average
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	1 Siemens SGT6-PAC-5000F 2227 MMBtu/hr plus 641 MMBtu/hr DF	870 lb CO2e/MWhr monthly average 842 lb/MWhr rolling 12-month average 1,094,900 tpy
Russell City Energy Center	Hayward, CA	02/03/2010	2 - Siemens 501F 2238.6 MMBtu/hr/unit plus 200 MMBtu/hr DF	Heat rate of 7,730 Btu HHV/kWhr 242 metric tons of CO2e/hr/both units 5,802 metric tons of CO2e/day/both units 1,928,102 metric tons of CO2e/year/both units 119 lb CO2e/MMBtu

[1] DF refers to duct firing
[2] Limits obtained from agency permitting documents when not available in RBLC

hybrid solar/gas turbine project, and the Palmdale GHG limits appear to account for the solar energy production component. The Footprint Project's available land and Massachusetts climate restrictions preclude a solar component which could achieve the Palmdale limits.

- The Brockton (MA) Project was approved for a rolling 12-month CO_2 limit of 842 lb/MWhr, and a monthly maximum of 870 lb/MWhr. The basis for the 842 lb/MWhr limit in the Massachusetts Plan Application for the Brockton Project is stated *to include operation at a variety of loads, ambient temperatures, with and without evaporative cooling, and with and without duct firing, and including starts and stops* (Brockton Power Plan Application at page 4-30). However, there is no mention of any allowance for heat rate (efficiency) degradation over the life of the project or between major turbine overhauls. This is a significant consideration which renders this value of 842 lb CO_2/MWhr as inappropriate as a GHG BACT precedent. Footprint notes that the Brockton Project has not been constructed, and the 842 lb/MWhr value therefore has not been demonstrated in practice. In addition, the Footprint notes that the Brockton Project did not specifically undergo a PSD review for GHG BACT. Footprint also notes that in the Plan Application for the Brockton Project, it is stated that the 842 lb/MWhr value is based on a CO_2 emission factor of 117 lb/MMBtu. Footprint notes its proposed limit of 895 lb/net MWhr is based on a CO_2e emission factor of 119 lb/MMBtu. Adjusting the Brockton value of 842 lb/MWhr by 119/117, the Brockton rate (based on 119 lb CO_2/MMBtu) would be 856 lb/MWhr. In this case, the Footprint Project value (895 lb/MWhr) is only 4.6% higher than the adjusted Brockton value (856 lb/MWhr). In addition, the Brockton Project design is based on wet cooling, while the Footprint Project will use dry cooling. Projects using dry cooling have higher heat rates (are less efficient) than wet cooled projects, particularly during the summer months. Reasonable allowance for heat rate (efficiency) degradation over the life of the project and between major turbine overhauls, as well as the impact of wet vs. dry cooling, explains the proposed GHG BACT for the SHR Project of 895 lb/net MWhr compared to the proposed Brockton limit.

CLF comments dated November 1, 2013 on the Footprint public review documents indicate that the Newark Energy Center has a combined cycle mode heat rate limit of 6005 Btu/kWhr, corresponding to a thermal efficiency of 58.4%. The CLF comments further note that the Russell Energy Center Project in CA has proposed to achieve a thermal efficiency of 56.4%, and the Cricket Valley Project (NY) proposed to achieve 57.4% efficiency. These values are taken from a letter written by Steve Riva dated April 17, 2012.

The Newark Energy Center quoted values of 6005 Btu/kWhr and 58.4% thermal efficiency appear to be preliminary values, since they do not match the actual New Jersey PSD Permit as discussed below. When comparing heat rate and efficiency values, these may be quoted with varying assumptions, and it is important to ensure an "apples to apples" comparison is made. The heat rate used to calculate thermal efficiency is typically specified based on full load ISO operation, no duct firing, gross output, and on an LHV basis. That is why it is commonly a lower value than "real world" rolling 12-month, net, HHV values. These two values (6005 Btu/kWhr and 58.4% thermal efficiency) are actually not consistent with each other, since thermal efficiency is calculated as 3412 Btu/kW-hr/6005 Btu/kW-hr = 56.8% thermal efficiency. In any event, the "real" numbers for the Newark Energy Center GHG BACT limits in Table 1-3 are taken from the actual New Jersey PSD permit dated November 1, 2012, so these represent more recent information for the Newark Energy Center Project. The actual Newark Energy Center permit has net "heat" rate limit (without duct firing at base load corrected to ISO conditions) of 7,522 Btu/kWhr based on the Higher Heating Value (HHV) of the fuel. As indicated above, the Footprint Project has a nearly numerically identical rolling 365-day GHG limit which corresponds to a net heat rate of 7,521 Btu/kWhr, but that reflects *all* annual operation and not just base load without duct firing. The Newark Energy Center also has a direct GHG limit of 887 lb/MWhr, gross basis, rolling 12-month average. The

Footprint rolling 365-day GHG limit of 895 lb/MWhr *net basis* is clearly more stringent than the actual Newark Energy Center GHG limit.

The Russell Energy Center PSD Permit has a heat rate limit of 7,730 Btu/kW-hr, with the key assumptions for calculating compliance not specified. In any event, this limit is clearly less stringent than Footprint's rolling 365-day GHG limit which corresponds to a net heat rate of 7,521 Btu/kWhr. Footprint's design thermal efficiency of 57.9% is also better than the quoted Russell proposal of 56.4% (not referenced in the Russell's actual PSD permit).

Cricket Valley's PSD permit does contain the quoted 57.4% thermal efficiency, and well as a heat rate limit of 7,605 Btu/kW-hr. The Cricket Valley PSD permit indicates this heat rate is at ISO conditions, HHV without duct firing. Gross or net electric output is not specified. As with Russell, this limit is clearly less stringent than Footprint's rolling 365-day GHG limit which corresponds to a net heat rate of 7,521 Btu/kWhr. Footprint's design thermal efficiency of 57.9% is also better than the Cricket Valley value 57.4%.

CLF suggests that the GHG limits should also be expressed on a thermal efficiency basis. As stated above, thermal efficiencies for gas turbines are normally based on the lower heating value (LHV) of the fuel, on a gross energy basis. The only PSD Permit we identified containing a thermal efficiency value is the Cricket Valley PSD permit. As MassDEP has done, Footprint concurs it is more appropriate to propose GHG limits directly as CO_2e on a *net* energy basis, accounting for actual emissions of GHG and overall project efficiency including parasitic plant loads.

In summary, the available evidence clearly indicates that PSD BACT for GHG for combustion turbines is use of low carbon fuel (e.g., natural gas) in high efficiency combustion combined cycle turbines. Footprint's proposed GHG limits are as or more stringent than any PSD BACT determinations, except for a hybrid solar facility, and the Brockton Power Project, which has a rolling 12-month limit which does not properly account for degradation over the life of the equipment. It is concluded that Footprint's proposed GHG limits represent PSD BACT.

1.1.6 Combustion Turbine Startup and Shutdown BACT

This section supplements the PSD BACT analysis for the combustion turbine startup and shutdown (SUSD) limits. Combustion turbine combined cycle units require warm up time to achieve proper operation of the dry-low NO_x combustors discussed above, and also to achieve system warm-up to allow proper function of the SCR catalysts. Combustion turbine combined cycle units require higher mass emission limits during SUSD operations for NO_x, CO and VOC. Since CO and VOC are not subject to PSD review, this SUSD BACT assessment only addresses NO_x. The other pollutants subject to PSD review are $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, as these pollutants have lower mass emissions than for normal operation and thus are not included in this PSD SUSD BACT evaluation. GHG also has the rolling 12-month limit (lb/MWhr) encompassing all operation including SUSD.

This evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for SUSD are procedures to warm up the systems and begin operation of the temperature-dependent emission control systems as quickly as practical, consistent with all system constraints. The Project incorporates new "quick start" technology which minimizes SUSD emissions significantly compared to prior startup procedures in widespread use. Table 1-4 presents the proposed NOx SUSD BACT limits for the Project:

Table 1-4. Combustion Turbine NOx SUSD PSD BACT Limits

Pollutant	Startup (lb/event)	Shutdown (lb/event)
NOx	89	10

In addition to these limits, the Project has a limit for startup duration of $\leq$ 45 minutes and for shutdown duration of $\leq$ 27 minutes. Also, the project is required to begin SCR operation (inject ammonia) as soon as the systems attain the minimum temperatures as specified by the control equipment system vendors, and other system parameters are satisfied for SCR operation.

As part of the review of these proposed NO_x SUSD BACT limits under the “top-down” procedure, Footprint has compiled all the NO_x SUSD PSD BACT determinations in the last five years for new gas-fired large (> 100 MW) combustion turbine combined cycle projects. This compilation is presented in Table 1-5. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. This review confirms that the only SUSD NO_x BACT technologies identified are procedures to warm up the systems and begin operation of the SCR as quickly as practical consistent with other constraints. Table 1-5 contains 28 new large (> 100 MW) combustion turbine combined cycle projects with NO_x SUSD PSD BACT determinations. These limits are generally expressed as either lb/hr or lb/event. Some units do not have numerical SUSD limits for NO_x, but only requirements to minimize SUSD emissions.

For purposes of comparing the Project limits to determinations only expressed in lb/hr, Footprint’s worst case lb/hr is calculated as 45 minutes for a cold start (at 89 pounds) plus 15 minutes at full load (18.1 lb/hr)/4 = 93.5 lb/hr. Also, while the Project’s proposed NO_x SUSD limits for a start are only for a worst-case cold start, for comparison purposes the Project’s values for a warm and hot start, as provided in the August 6, 2013 Application Supplement, are 54 and 28 pounds, respectively.

All the NO_x SUSD BACT limits in Table 1-5 are less stringent than the Footprint limits, except for the warm start limits at two CA projects (Palmdale and Victorville), and startup/shutdown limits for the Brockton MA Project. Palmdale and Victorville each have the same limit for a warm and hot start of 40 lbs/event, while the Footprint values are 54 lbs for a warm start and 28 lbs for a hot start. It is logical that a warm start would have higher emissions than a hot start, and the average of the two Footprint values (54 lbs and 28 lbs) is 41 lbs/event, effectively identical to the Palmdale and Victorville value.

The Brockton project is based on a “quick start” Siemens SGT6-PAC-5000F combined cycle installation, and has approved SUSD limits of 31.6 lb/hr (startup) and 29.8 lb/hr (shutdown). The startup time is stated as 0.47 hours and the shutdown time is 0.40 hours. Thus, the lb/event values are calculated as 14.9 pounds for a start and 11.9 pounds for a shutdown. Footprint did consider a very similar Siemens turbine subsequent to the approval data of the Brockton permit, and this more recent data for the same basic “quick start” Siemens machine (5000F) now has 83 lbs NO_x over 45 minutes. For a combined cold start and shutdown, Footprint now has (89 +10 = 99) lbs NO_x while the Siemens data provided to Footprint reflects (83 + 20 = 103) lbs NO_x. GE has lower NO_x emissions for both the warm and hot start. So, based on the latest information, there is no advantage to selecting Siemens over GE for NO_x startup/shutdown emissions based on more recent data.

Table 1-5. Summary Of Recent NOx SUSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] SUSD NOx (values are for a single unit at multiple unit facilities)
Carroll County Energy	Washington Twp., OH	11/5/2013	2 GE 7FA 2045 MMBtu/hr/unit plus 566 MMBtu/hr DF	Cold Start: 476 lbs/event Warm Start: 290 lbs/event Hot Start: 160 lbs/event Shutdown: 77 lbs/event Values calculated from approved lb/hr and event durations
Renaissance Power	Carson City, MI	11/1/2013	4 Siemens 501 FD2 units 2147 MMBtu/hr/unit each with 660 MMBtu/hr DF	176.9 lb/hr SU and 147.3 lb/hr SD
Langley Gulch Power	Payette, ID	08/14/2013	1 - Siemens SGT6-5000F 2134 MMBtu/hr/unit with 241.28 MMBtu/hr DF	96 ppm; 3 hr rolling average *(for the amount of fuel firing during SUSD for a GE 7FA, 96 ppm corresponds to approximately 450 lbs over a 45 minute quick start)*
Oregon Clean Energy	Oregon, OH	06/18/2013	2 Mitsubishi M501GAC or 2 Siemens SCC6-8000H 2932 MMBtu/hr/unit plus 300 MMBtu/hr DF	Mitsubishi: Cold Start: 108.9 lbs/event Warm Start: 86 lbs/event Hot Start: 47.2 lbs/event Shutdown: 35 lbs/event Siemens: – Cold Start: 188 lbs/event Warm Start: 126 lbs/event Hot Start: 108 lbs/event Shutdown: 46 lbs/event Values calculated from approved lb/hr and event durations
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	2 GE 7FA.05 2230 MMBtu/hr/unit plus 650 MMBtu/hr DF or 2 Siemens SGT6-5000F5 2260 MMBtu/hr/unit plus 450 MMBtu/hr DF	Minimize emissions, No numeric limits
Brunswick County Power	Freeman, VA	03/12/2013	3 Mitsubishi M501 GAC with DF Combined GT and DF 3442 MMBtu/hr/unit	Minimize emissions, No numeric limits
Garrison Energy Center	Dover, DE	01/30/2013	GE 7FA 309 MW	Cold Start/: 500 lbs/event Warm/Hot Start/: 200 lbs/event Shutdown: 23 lbs/event
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	4 - "F Class" (GE or Siemens) 1345 MW total	443 lb/event
Hess Newark Energy Center	Newark, NJ	11/01/2012	2 - GE 7FA.05 2320 MMBtu/hr/unit plus 211 MMBtu/hr DF	Cold Start: 140.6 lbs/event Warm Start: 96.8 lbs/event Hot Start: 95.2 lbs/event Shutdown: 25 lbs/event

Table 1-5. Summary Of Recent NOx SUSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] SUSD NOx (values are for a single unit at multiple unit facilities)
Channel Energy Center, LLC	Houston, TX	10/15/2012	2 - Siemens 501F 180 MW plus 425 MMBtu/hr DF	350 lb/hr
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	Siemens "H Class" 2 – 468 or less MW combined cycle blocks GT ≤ 2890 MMBtu/hr/unit DF ≤ 3870 MMBtu/hr/unit	No SUSD listed in RBLC
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	1 - Siemens 501F 180 MW plus 725 MMBtu/hr DF	350 lb/hr
ES Joslin Power	Calhoun, TX	09/12/2012	3 - GE 7FA 195 MW per unit No DF	99.9 lb/hr
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	1 Mitsubishi M501GAC 2542 MMBtu/hr/unit; no DF	62 lb/hr (310 lbs/event for cold start) (124 lbs/event for warm start (62 lbs/event for shutdown)
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	2 GE 7FA 154 MW (1736 MMBtu/hr) per unit plus 500 MMBtu/hr DF	Cold Start: 96 lbs/event Warm/Hot Start: 40 lbs/event Shutdown: 57 lbs/event
Thomas C. Ferguson Power	Llano, TX	09/01/2011	2 - GE 7FA 195 MW per unit No DF	111.56 lb/hr
Entergy Ninemile Point Unit 6	Westwego, LA	08/16/2011	Vendor not specified Single unit 550MW	No SUSD in RBLC
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	1 Siemens SGT6-PAC-5000F 2227 MMBtu/hr plus 641 MMBtu/hr DF	Start: 31.6 lb/hr Shutdown: 29.8 lb/hr
Avenal Power Center	Avenal, CA	05/27/2011	2 - GE 7FA 1856.3 MMBtu/hr/unit plus 562.26 MMBtu/hr DF	Each unit: 160 lb/hr Both units: 240 lb/hr
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	1 - Mitsubishi M501GAC 2866 MMBtu/hr	150 lb/hr; 3-hr rolling average
Dominion Warren County	Front Royal, VA	12/21/2010	3 -Mitsubishi M501 GAC 2996 MMBtu/hr/unit plus 500 MMBtu/hr DF	Minimize emissions, No numeric limits
Pondera/King Power Station	Houston, TX	08/05/2010	4 GE 7FA.05 2430 MMBtu/hr/unit GT plus DF or 4 Siemens SGT6-5000F5 2693 MMBtu/hr/unit GT plus DF	GE: 216 lb/hr/unit Siemens: 220 lb/hr/unit
Live Oaks Power	Sterling, GA	03/30/2010	Siemens SGT6-5000F	Minimize emissions, No numeric limits

Table 1-5. Summary Of Recent NOx SUSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] SUSD NOx (values are for a single unit at multiple unit facilities)
Victorville 2 Hybrid	Victorville, CA	03/11/2010	2 GE 7FA 154 MW per unit plus 424.3 MMBtu/hr DF	Cold Start: 96 lbs/event Warm/Hot Start: 40 lbs/event Shutdown: 57 lbs/event
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	2 GE 7FA 170 MW/unit plus 570 MMBtu/hr DF or 2 Mitsubishi M501G 254 MW/unit plus 230 MMBtu/hr DF	GE: 420 lb/hr/unit Mitsubishi: 239 lb/hr/unit
Russell City Energy Center	Hayward, CA	02/03/2010	2 - Siemens 501F 2238.6 MMBtu/hr/unit plus 200 MMBtu/hr DF	Cold Start: 480 lbs/event/unit Warm Start: 125 lbs/event/unit Hot Start: 95 lbs/event/unit Shutdown: 40 lbs/event/unit
Panda Sherman Power	Grayson, TX	02/03/2010	2 GE 7FA or 2 Siemens SGT6-5000F with 468 MMBtu/hr/unit DF	GE: 242 lb/hr/unit Mitsubishi: 148.5 lb/hr/unit
Lamar Power Partners II LLC	Paris, TX	06/22/2009	4 - GE 7FA with 200 MMBtu/hr DF	No SUSD limits in RBLC or TX permit
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	4 – GE 7FA, GE7FB, or Siemens SGT6-5000F With DF	650 lb/hr/unit (each option)
Entergy Lewis Creek Plant	The Woodlands, TX	05/19/2009	2 - GE 7FA with 362 MMBtu/hr DF	200 lb/hr

[1] DF refers to duct firing: [2] Short-term limits only. Limits obtained from agency permitting documents when not available in RBLC.

PVEC does have a somewhat more stringent NO_x SUSD BACT limit on an hourly basis (62.0 lbs per hour) compared to the equivalent Footprint lb/hr value of 93.5 lbs/hr. However, PVEC has longer startup and shutdown times, with up to 5 hours for a cold start, 2 hours for a warm start, and 1 hour for a shutdown. On a pound per event basis, PVEC has greater SUSD emissions compared to Footprint.
Footprint will achieve the lowest practical emissions achievable for SUSD, and the proposed PSD permit allows the MassDEP to reset the SUSD BACT limits if different values are demonstrated to be achievable.

1.2 Auxiliary Boiler

This section supplements the PSD BACT analysis for the auxiliary boiler to address public comments made on the draft permit documents. The Project is subject to PSD review for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, and thus the auxiliary boiler is subject to PSD BACT for these pollutants.

The Project includes an 80 MMBtu/hr auxiliary boiler that will have natural gas as the only fuel of use. Table 1-6 presents the proposed BACT limits for the auxiliary boiler for pollutants subject to PSD review.

Table 1-6. Auxiliary Boiler Proposed PSD BACT Limits

Pollutant	Emission Limitation	Control Technology
NOx	9 ppmvd at 3% O_2 0.011 lbs/MMBtu	Ultra Low NOx Burners (9 ppm) Good combustion practices Natural gas
$PM/PM_{10}/PM_{2.5}$	0.005 lbs/MMBtu	
H_2SO_4	0.0009 lbs/MMBtu	Natural Gas
GHG as CO2e	119.0 lb/MMBtu	Natural Gas

(Note: the H_2SO_4 value is revised to reflect the inclusion of a CO oxidation catalyst)

In order to inform the PSD BACT process, Footprint has compiled all the PSD BACT determinations in the last five years for auxiliary boilers at new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. Table 1-7 provides this compilation. Table 1-7 will be referred to in the individual pollutant discussion below.

1.2.1 Fuel Selection

Step 1: Identify Candidate Fuels

- Natural gas
- ULSD

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible.

Step 3: Rank Control Technologies by Control Effectiveness

Natural gas boilers can achieve lower emissions compared to ULSD.

Step 4: Evaluate Controls

Footprint has chosen the lowest emitting fuel for the auxiliary boiler, natural gas. Therefore, a detailed evaluation of alternate fuels is not required.

Step 5: Select BACT
Natural gas is proposed as the BACT fuel for the auxiliary boiler.

Table 1-7. Summary Of Recent PSD BACT Determinations for Natural Gas Auxiliary Boilers at Large (>100MW) Gas Fired Combined-Cycle Generating Plants for NO_x, PM, H_2SO_4, GHG

Facility	Location	Permit Date	Auxiliary Boiler Size MMBtu/hr	Emission Limits[1] (lb/MMBtu except where noted) NOx	PM/PM10/PM2.5	H2SO4	GHG
Carroll County Energy	Washington Twp., OH	11/5/2013	99	0.02	0.008	0.00022	26,259.76 tpy
Renaissance Power	Carson City, MI	11/1/2013	(2) - 40	0.035	0.005	--	11,503.7 tpy (both units)
Oregon Clean Energy	Oregon, OH	06/18/2013	99	0.02	0.008	0.00011	11,671 tpy
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	75	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	Pipeline natural gas < 0.1 gr S/100scf	--	Pipeline natural gas
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	40	0.011	0.005	0.0005	13,696 tpy
Sunbury Generation	Sunbury, PA	04/01/2013	Not provided (repowered unit)	0.036	0.008	--	--
Brunswick County Power	Freeman, VA	03/12/2013	66.7	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	Pipeline natural gas < 0.4 gr S/100scf	Pipeline natural gas < 0.4 gr S/100scf	Pipeline natural gas
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) - 80	0.032	0.0075	--	81,996 tpy; 80% efficiency
Hess Newark Energy Center	Newark, NJ	11/01/2012	66.2	0.66 lb/hr (based on 0.010 lb/MMBtu)	0.33 lb/hr (based on 0.005 lb/MMBtu)	0.006 lb/hr (=0.0001 lb/MMBtu at full load)	7,788 lb/hr
Channel Energy Center, LLC	Houston, TX	10/15/2012	(3) - 430	21.6 lb/hr/unit (=0.05 lb/MMBtu at full load)	7.8 lb/hr/unit (=0.018 lb/MMBtu at full load)	1.0 lb/hr/unit (=0.002 lb/MMBtu at full load)	--
Cricket Valley	Dover, NY	09/27/2012	60	0.011	0.005	--	--
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	21	0.029	0.0048	0.0005	--
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	110	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	0.33 lb/hr (=0.003 lb/MMBtu at full load)	--	Annual tuneup
Entergy Nine-mile Point Unit 6	Westwego, LA	08/16/2011	338	--	7.6 lb/MMscf (= 0.0076 lb/MMBtu)	--	117 lb/MMBtu
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	60	0.011	0.01	--	--

Table 1-7. Summary Of Recent PSD BACT Determinations for Natural Gas Auxiliary Boilers at Large (>100MW) Gas Fired Combined-Cycle Generating Plants for NO_x, PM, H_2SO_4, GHG

Facility	Location	Permit Date	Auxiliary Boiler Size MMBtu/hr	Emission Limits[1] (lb/MMBtu except where noted)			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Avenal Power Center	Avenal, CA	05/27/2011	37.4	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	0.34 grains S/100 dscf and pipeline quality gas	--	--
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	91	50 lb/MMscf (= 0.05 lb/MMBtu)	2.5 lb/MMscf (= 0.0025 lb/MMBtu)	--	--
Dominion Warren County	Front Royal, VA	12/21/2010	88.1	0.011 lb/MMBtu	0.44 lb/hr (=0.005 lb/MMBtu at full load)	--	--
Pondera/King Power Station	Houston, TX	08/05/2010	(2) - 45	0.45 lb/hr/unit (=0.01 lb/MMBtu at full load)	0.32 lb/hr/unit (=0.007 lb/MMBtu at full load)	--	--
Victorville 2 Hybrid	Victorville, CA	03/11/2010	35	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	0.2 grains S/100 dscf and pipeline quality gas	--	--
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	142	1.42 lb/hr/unit (=0.01 lb/MMBtu at full load)	1.06 lb/hr/unit (=0.0075 lb/MMBtu at full load)	--	--
Panda Sherman Power	Grayson, TX	02/03/2010	53	0.53 lb/hr/unit (=0.01 lb/MMBtu at full load)	0.53 lb/hr/unit (=0.01 lb/MMBtu at full load)	--	--
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	(4) - 40	1.4 lb/hr/unit (=0.01 lb/MMBtu at full load)	0.3 lb/hr/unit (=0.0075 lb/MMBtu at full load)	--	--

[1]Short term limits only for NOx, PM, and H2SO4. Limits obtained from agency permitting documents when not available in RBLC

1.2.2 NOx

Step 1: Identify Candidate Control Technologies

- Selective Catalytic Reduction
- Ultra-Low NOx burner
- Low NOx burner, typically with flue gas recirculation

Step 2: Eliminate Infeasible Technologies

All these technologies are technically feasible, although application of SCR is unusual for natural gas boilers in this size range.

Step 3: Rank Control Technologies by Control Effectiveness

The ranking of these technologies is as follows:

1. SCR: Demonstrated to have achieved less than 5.0 ppmvd NO_x at 3% O_2 for gas fired boilers. Can be used as supplemental control with a low NO_x burner but not demonstrated with an ultra-low-NO_x burner.
2. Ultra-Low NOx burner: Demonstrated to have achieved 9 ppmvd NO_x at 3% O2
3. Low NOx burner, typically with flue gas recirculation: Generally recognized to achieve 30 ppmvd NO_x at 3% O_2.

Step 4: Evaluate Controls

Since SCR is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 1-8. The capital cost estimate for an SCR system and an ultra-low NO_x burner are based on information provided by Cleaver Brooks. The SCR has been conservatively assumed to control 90% of the potential NO_x emissions (to 3 ppmvdc at 3% O_2) even though 5 ppmvdc has been approved in past projects. Control to this NO_x level is likely to correspond to an ammonia slip level of 10 ppm at 3% O_2. Table 1-8 indicates that the average and particularly the incremental cost effectiveness of an SCR are excessive, at over $19,000 per ton for average cost of control, and nearly $70,000 per ton on an incremental basis. The ultra-low-NO_x burner is cost effective and is the proposed BACT. There are no energy or environmental issues with ultra-low NO_x burners that would indicate selection of SCR as BACT, given the unfavorable SCR economics.

Step 5: Select BACT

With respect to NO_x, the lowest limit identified for any of the power plant auxiliary boilers in Table 1-7 is consistent with the standard guarantee for ultra-low-NOx burners, which is 9 ppmvd at 3% O_2. This corresponds to 0.011 lb/MMBtu. There are several boilers with BACT limits for NOx in lb/hr calculated with 0.01 rather than 0.011 lb/MMBtu, but this is considered effectively the same limit at full load and is actually less stringent at part-load, since the limits expressed as 9 ppmvd at 3% O_2/0.011 lb/MMBtu apply throughout the load range. The Project auxiliary boiler meets this most stringent limit found for natural gas-fired auxiliary boilers at new large (> 100 MW) combustion turbine combined cycle projects.

Table 1-8. Summary of Auxiliary Boiler Top-Down BACT Analysis for NOx

Control Alternative	NOx Emissions			Economic Impacts				Energy Impacts (compared to baseline)	Environmental Impacts	
	ppmvd @ 3% O2	Tons per year (tpy)	Emissions Reduction Compared to Baseline (tpy)	Installed Capital Cost (differential over baseline)	Total Annualized Cost (differential over baseline)	Average Cost Effectiveness	Incremental Cost Effectiveness		Toxics Impacts (Yes/No)	Adverse Environmental Impacts (Yes/No)
SCR	3	0.95	8.51	$414,750	$162,668	$19,115	$69,786	Small	Yes	No
ULN	9	2.89	6.57	$134,400	$27.283	$4,153	--	negligible	No	No
LN (baseline)	30	9.46	--	--	--	--	--			

SCR – Selective Catalytic Reduction
ULN – Ultra low-NOx burner
LN – Low NOx burner

See Appendix A, Calculation Sheets 8 and 9, for calculation of cost values.

1.2.3 $PM/PM_{10}/PM_{2.5}$

For $PM/PM_{10}/PM_{2.5}$, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for $PM/PM_{10}/PM_{2.5}$. The "top-down" procedure does require selection of BACT emission limits, which is addressed in the following paragraphs.

Table 1-7 presents the review of BACT precedents for auxiliary boilers. With respect to $PM/PM_{10}/PM_{2.5}$, for limits expressed in mass units (lb/MMBtu or lb/hr converted to lb/MMBtu at full load), only two of the auxiliary boilers listed in the Table 1-7 have $PM/PM_{10}/PM_{2.5}$ limits that are more stringent than the Project auxiliary boiler limit of 0.005 lb/MMBtu. One of these boilers is at the Palmdale Hybrid Power facility, with a limit of 0.33 lb/hr, which corresponds to 0.003 lb/MMBtu at full load. However, this lb/hr limit could be met by reducing the boiler load, if the actual emissions exceed 0.003 lb/MMBtu. So at lower loads it is actually less stringent than the Project limit of 0.005 lb/MMBtu, which applies throughout the load range. The other boiler listed in the RBLC with a lower lb/MMBtu emission limit is at the Portland (OR) General Electric Carty Plant. This limit of 2.5 lb/MMcf of natural gas (which corresponds to 0.0025 lb/MMBtu) is considered unrealistically low for a guarantee for a boiler of this type. This is because of uncertainty and variability with available $PM/PM_{10}/PM_{2.5}$ test methods, and the risk of artifact emissions resulting in a tested exceedance. All new gas-fired boilers, properly operated, are expected to have intrinsically low $PM/PM_{10}/PM_{2.5}$ emissions. A limit of 0.005 lb/MMBtu is within the range of recent PSD BACT levels and is justified as PSD BACT.

Several of the boilers listed in Table 1-7 have $PM/PM_{10}/PM_{2.5}$ PSD BACT limits expressed as the sulfur content of the natural gas. These values range from 0.1 grains/100 scf to 0.4 grains/100 scf. All of these values are lower than what USEPA defines as the maximum sulfur content of pipeline natural gas (0.5 grains/100 scf). The Applicant does not believe it is prudent to assume a natural gas sulfur content lower than EPA's definition for pipeline natural gas. Therefore, these sulfur limits for $PM/PM_{10}/PM_{2.5}$ PSD BACT limits are not appropriate.

1.2.4 H_2SO_4

For H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for H_2SO_4 is limiting the fuel sulfur content. Based on the selection of natural gas as the BACT fuel, this is the lowest sulfur content fuel suitable for the auxiliary boiler.

The BACT process for H_2SO_4 proceeds directly to the selection of BACT. Footprint has based the H_2SO_4 limit on 40% molar conversion of fuel sulfur to H_2SO_4. This is because Footprint has incorporated a CO oxidation catalyst to reduce CO emissions. One of the collateral impacts of this oxidation catalyst is an increase in H_2SO_4 emissions. With respect to H_2SO_4, none of the 6 of the projects in Table 1-7 with numeric H_2SO_4 limits have oxidation catalysts. Therefore, the proposed Project limit is less stringent than 5 of these 6 limits. The proposed Project limit of 0.0009 lb/MMBtu H_2SO_4 is justified as PSD BACT with the addition of a CO catalyst.

1.2.5 GHG

For GHG, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion controls suitable for GHG. The BACT process for GHG proceeds directly to the selection of BACT.

With respect to GHG, most of the auxiliary boilers listed in Table 1-7 with GHG limits for PSD BACT are expressed as a mass emission value, which is a project specific number reflecting the particular size and gas throughput limits of the specific project unit. For its proposed GHG limit for the Auxiliary Boiler, the Project has chosen a conservative value based on the USEPA Part 75 default emission factor (119 lb/MMBtu). Another unit listed in the RBLC has an 80% efficiency specified in addition to an annual mass limit. This is the only auxiliary boiler approved with this type of limit. The Project will install an auxiliary boiler with a nominal efficiency of 83.7%. The Applicant proposes a GHG PSD BACT limit expressed in the units of lb/MMBtu (119 lb/MMBtu) as most appropriate PSD BACT limit.

1.3 Emergency Diesel Generator

This section supplements the PSD BACT analysis for the emergency diesel generator to address public comments made on the draft permit documents. The Project is subject to PSD review for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, and thus the emergency diesel generator is subject to PSD BACT for these pollutants.

The Project includes a 750 kW emergency diesel generator that will have ultra-low sulfur diesel (ULSD) as the only fuel of use. Table 1-9 presents the proposed BACT limits for the emergency diesel generator for pollutants subject to PSD review.

Table 1-9. Emergency Diesel Generator Proposed PSD BACT Limits

Pollutant	Emission Limitation (grams/kWhr)	Emission Limitation (grams/hphr)
NOx	6.4	4.8
$PM/PM_{10}/PM_{2.5}$	0.20	0.15
H_2SO_4	0.0009 lb/hr (0.00012 lb/MMBtu)	
GHG as CO2e	162.85 lb/MMBtu	

The proposed PSD BACT limits for NO_x and $PM/PM_{10}/PM_{2.5}$ are based on compliance with the EPA New Source Performance Standards (NSPS), 40 CFR 60 Subpart IIII. For a 750 kW engine, Subpart IIII requires what is referred to as a Tier 2 engine. For H_2SO_4, the PSD BACT limit is based on use of ultra-low sulfur diesel (ULSD) fuel, and conversion of 5% of the fuel sulfur on a molar basis to H_2SO_4. The GHG limit is based on EPA emission factors for ULSD.

In order to inform the PSD BACT process, Footprint has compiled all the PSD BACT determinations in the last five years for emergency generators at new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. Table 1-10 provides this compilation. Review of Table 1-10 indicates that only one emergency generator is fired with natural gas, and all the others are fired with ULSD. The gas-fired engine, at Avenal Power Center in CA, does have SCR to control NOx. All other emergency generators in Table 1-10 do not have any post combustion controls for PSD pollutants. Table 1-10 will be referred to in the individual pollutant discussion below.

Table 1-10. Summary Of Recent PSD BACT Determinations for Emergency Generators at Large (>100MW) Gas Fired Combined-Cycle Generating Plants for NO_x, PM, H_2SO_4, GHG

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits[1]			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Carroll County Energy	Washington Twp., OH	11/5/2013	1112 kW	Subpart IIII		0.000132 grams/kWhr	433.96 tpy
Renaissance Power	Carson City, MI	11/1/2013	(2) – 1000 kW	Subpart IIII		--	1731.4 tpy (both units)
Langley Gulch Power	Payette, ID	08/14/2013	750 kW	Subpart IIII		--	--
Oregon Clean Energy	Oregon, OH	06/18/2013	2250 kW	Subpart IIII		0.000132 grams/kWhr	877 tpy (87)
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	1500 kW	Subpart IIII		--	Low carbon fuel and efficient operation
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	750 kW	6.0 grams/kWhr	0.25 grams/kWhr	--	80.5 tpy
Brunswick County Power	Freeman, VA	03/12/2013	2200 kW	Subpart IIII		ULSD	Low carbon fuel and efficient operation
Moxie Patriot LLC	Clinton Twp PA	01/31/2013	1472 hp	4.93 grams/hp-hr	0.02 grams/hp-hr	--	--
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) – 1006 hp	Subpart IIII		--	1186 tpy
Hess Newark Energy Center	Newark, NJ	11/01/2012	1500 kW	Subpart IIII		--	--
Moxie Liberty LLC	Asylum Twp, PA	10/10/2012		4.93 grams/hp-hr	0.02 grams/hp-hr	--	--
Cricket Valley	Dover, NY	09/27/12	4 Black Start EDGs 3000 kW each	Subpart IIII		--	--
ES Joslin Power	Calhoun, TX	09/12/2012	(2) -EDG	14.11 lb/hr/unit	0.44 lb/hr/unit	--	--
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	2174 kW	Subpart IIII		--	--
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	110	Subpart IIII		--	--
Thomas C. Ferguson Power	Llano, TX	09/01/2011	1340 hp	16.52 lb/hr *(5.5 grams/hp-hr)*	0.55 lb/hr	--	15,314 lb/hr 30 day rolling average 765.7 tpy 365 day rolling average
Entergy Nine-mile Point Unit 6	Westwego, LA	08/16/2011	1250 hp	--	Subpart IIII	--	CO_2e 163.6 lb/MMBtu,

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits[1]			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Avenal Power Center	Avenal, CA	05/27/2011	550 kW natural gas engine	SCR to 1 gram/hp-hr	0.34 gram/hp-hr	--	--
Dominion Warren County	Front Royal, VA	12/21/2010	2193 hp	Subpart IIII		--	--
Pondera/King Power Station	Houston, TX	08/05/2010	Size not given	26.61 lb/hr	1.88 lb/hr	--	--
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	3- 2000 kW each	5.45 gm/hp-hr	0.032 gm/hp-hr	--	--
Victorville 2 Hybrid	Victorville, CA	03/11/2010	2000 kW	Subpart IIII		--	--
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	750 hp	23.25 lb/hr (14 grams/hp-hr)	1.65 lb/hr (1.0 grams/hp-hr)	--	--
Panda Sherman Power	Grayson, TX	02/03/2010	Size not given	35.24 lb/hr	0.17 lb/hr	--	--
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	Size not given	18.0 lb/hr	0.5 lb/hr	--	--

[1] Generators are diesel generators except where noted.
[2] Short term limits only for NOx, PM, and H2SO4. Limits obtained from agency permitting documents when not available in RBLC.

1.3.1 Fuel Selection

Step 1: Identify Candidate Fuels

- Natural gas
- ULSD

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although use of natural gas is unusual for an emergency engine.

Step 3: Rank Control Technologies by Control Effectiveness

Natural gas engines can achieve lower emissions compared to ULSD.

Step 4: Evaluate Controls

Normally, for an emergency generator, it is very important to have the fuel supply directly available without the possibility of a natural gas supply interruption making it impossible to operate the emergency generator in an emergency. The purpose of the emergency generator is to be able to safely shut the plant down in the event of an electric power outage. So in order to maintain this important equipment protection function, ULSD, which can be stored in a small tank adjacent to the emergency generator, is the fuel of choice. Footprint is not aware of the specific circumstance for the emergency generator fuel selection at Avenal, but Footprint does not believe a natural gas fired generator for the Salem Project is a prudent choice.

Step 5: Select BACT

ULSD is proposed as the BACT fuel for the Project emergency generator.

1.3.2 NO_x

Step 1: Identify Candidate Control Technologies

- Selective Catalytic Reduction
- Low NO_x engine design in accordance with EPA NSPS, 40 CFR 60 Subpart IIII (Tier 2 engine for 750 kW unit)

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although application of SCR is unusual for an emergency engine.

Step 3: Rank Control Technologies by Control Effectiveness

SCR can normally achieve 90% remove of NO_x emissions, so it is more effective than the Tier 2 engine design which is based on low-NO_x engine design. However, for an emergency generator, if this unit is used just for short period of test and facility shutdown in an actual emergency, the ability of the SCR to control emissions will be significantly reduced since the engine/SCR takes time to warm up to achieve good NO_x control.

Step 4: Evaluate Controls

Since SCR is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 1-11. The capital cost estimate for an SCR system is based on information provided by Milton Cat Power Systems. The other factors are from the OAQPS Cost Control Manual. The SCR has been conservatively assumed to control 90% of the potential NO_x emissions even though this is unlikely in this application. Table 1-11 indicates that the cost effectiveness of an SCR is over $33,000 per ton of NO_x. This cost is excessive, even if the emergency generator runs the maximum allowable amount of 300 hours per year (unlikely) and 90% NO_x control of the full potential to emit is achieved.

There are no energy or environmental issues with a Tier 2 generator that would indicate selection of SCR as BACT, given the unfavorable SCR economics.

Step 5: Select BACT

With respect to the selection of a PSD BACT for NO_x for the emergency generator, Table 1-10 indicates that compliance with Subpart IIII is the most common limit. Several BACT determinations contain gram/kWhr or gram/hp-hr limits that approximate the Subpart IIII values but do not specifically reference Subpart IIII. Several Texas projects have lb/hr limits but do not provide the engine size to determine limits per unit of output.

Overall, with the elimination of SCR on economic grounds, the review of other RBLC precedents supports the selection of Subpart IIII compliance as BACT.

1.3.3 PM/PM_{10}/$PM_{2.5}$

Step 1: Identify Candidate Control Technologies

- Active Diesel Particulate Filter (DPF)
- Low PM engine design in accordance with EPA NSPS, 40 CFR 60 Subpart IIII (Tier 2 engine for 750 kW unit)

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although application of a DPF is unusual for an emergency engine.

Step 3: Rank Control Technologies by Control Effectiveness

An active DPF can achieve up to 85% particulate removal (CARB Level 3), so it is more effective than the Tier 2 engine design which is based on low-emission engine design.

Step 4: Evaluate Controls

Since a DPF is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 1-12. The capital cost estimate for an active system is based on information provided by Milton Cat Power Systems. The other factors are from the

OAQPS Cost Control Manual. Table 1-12 indicates that the cost effectiveness of an active DPF is over \$600,000 per ton of $PM/PM_{10}/PM_{2.5}$. This cost is excessive, even if the emergency generator runs the maximum allowable amount of 300 hours per year (unlikely).

TABLE 1-11 750 KW EMERGENCY GENERATOR
ECONOMIC ANALYSIS - SELECTIVE CATALYTIC REDUCTION -

BACT Assessment
Control System Life: 10 years
Interest Rate: 10.00%
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) 0.163

Baseline NOx Emissions per 40 CFR 60 Subpart IIII (tpy): 1.74
SCR Control Efficiency (%): 90%

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estimate (Per Milton Cat)		$150,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$7,500
Total Equipment Cost (TEC)			**$157,500**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$12,600
b.	Erection and Handling	(TEC*0.14)	$22,050
c.	Electrical	(TEC*0.04)	$6,300
d.	Piping	(TEC*0.02)	$3,150
e.	Insulation	(TEC*0.01)	$1,575
f.	Painting	(TEC*0.01)	$1,575
Total Direct Installation Cost			**$47,250**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$15,750
b.	Construction/Field Expenses	(TEC*0.05)	$7,875
c.	Construction Fee	(TEC*0.1)	$15,750
d.	Start up	(TEC*0.02)	$3,150
e.	Performance Test	(TEC*0.01)	$1,575
Total Indirect Installation Cost			**$44,100**
Total Capital Cost (TCC)			**$248,850**

Capital Recovery		**$40,563**
Direct Operating Costs		
a.	Ammonia	$2,256
b	Operating Labor (OL):(0.5 hr/shift)($25.6/hr)	$480
c.	Maintenance Labor (ML):(0.5 hr/shift)($25.6/hr)	$480
d	Maintenance Materials = Maintenance Labor	$480
Total Direct Operating Cost		**$960**
Catalyst Replacement is not included since the emergency generator will only operate a maximum of 300 hours in any year		
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$576
b.	Property Tax: (TCC*0.01)	$2,489
c.	Insurance: (TCC*0.01)	$2,489
d.	Administration: (TCC*0.02)	$4,977
Total Indirect Operating Cost		**$10,531**
Total Annual Cost		$52,054
NOx Reduction (tons/yr)		1.57
Cost of Control ($/ton - NOx)		$33,230

Note 1: Ammonia cost based on estimated as delivered cost for 19% aqueous ammonia of $0.60 per pound of ammonia, and 1.2 lbs of NH3 injected per pound of NOx removed

TABLE 1-12 750 KW EMERGENCY GENERATOR
ECONOMIC ANALYSIS - ACTIVE DIESEL PARTICULATE FILTER

BACT Assessment						
Control System Life:	10 years					
Interest Rate:	10.00%			Baseline PM Emissions per 40 CFR 60 Subpart IIII (tpy):		0.06
Economic Factors from MassDEP Form BWP-AQ-BACT				DPF Control Efficiency (%):		85%
Capital Recovery Factor (CRF)	0.163					
Equipment Cost (EC)	(Factor)			**Capital Recovery**		**$24,338**
a. DPF Capital Cost Estimate (per Milton Cat)		$90,000				
b. Instrumentation (0.10A)		Included		Direct Operating Costs		
c. Taxes and Freight	(EC*0.05)	$4,500	a	Operating Labor (OL):(0.25 hr/shift)($25.6/hr)		$240
			b	Maintenance Labor (ML):(0.25 hr/shift)($25.6/hr)		$240
Total Equipment Cost (TEC)		**$94,500**	c.	Maintenance Materials = Maintenance Labor		$240
Direct Installation Costs				**Total Direct Operating Cost**		**$720**
a. Foundation	(TEC*0.08)	$7,560				
b. Erection and Handling	(TEC*0.14)	$13,230				
c. Electrical	(TEC*0.04)	$3,780		DPF Replacement is not included since the emergency generator		
d. Piping	(TEC*0.02)	$1,890		will only operate a maximum of 300 hours in any year		
e. Insulation	(TEC*0.01)	$945				
f. Painting	(TEC*0.01)	$945				
Total Direct Installation Cost		**$28,350**				
				Indirect Operating Costs		
			a.	Overhead (60% of OL+ML)		$288
Indirect Installation Costs			b.	Property Tax: (TCC*0.01)		$1,493
a. Engineering and Supervision	(TEC*0.1)	$9,450	c.	Insurance: (TCC*0.01)		$1,493
b. Construction/Field Expenses	(TEC*0.05)	$4,725	d.	Administration: (TCC*0.02)		$2,986
c. Construction Fee	(TEC*0.1)	$9,450				
d. Start up	(TEC*0.02)	$1,890		**Total Indirect Operating Cost**		**$6,260**
e. Performance Test	(TEC*0.01)	$945				
				Total Annual Cost		**$31,318**
Total Indirect Installation Cost		**$26,460**				
				PM Reduction (tons/yr)		**0.05**
Total Capital Cost (TCC)		**$149,310**				
				Cost of Control ($/ton - PM)		**$614,080**

There are no energy or environmental issues with a Tier 2 generator that would indicate selection of a DPF as BACT, given the unfavorable economics.

Step 5: Select BACT

With respect to the selection of a PSD BACT for $PM/PM_{10}/PM_{2.5}$ for the emergency generator, Table 1-10 indicates that compliance with Subpart IIII is the most common limit. There are two BACT determinations for PA projects (Moxie projects) that both have very low $PM/PM_{10}/PM_{2.5}$ limits of 0.02 gram/hp-hr. Footprint suspects that this limit is a mistaken entry for the Subpart IIII value of 0.2 grams/kWhr. Several Texas projects have lb/hr limits but do not provide the engine size to determine limits per unit of output. Brockton (MA) also has a very low PM limit, much lower than the Subpart IIII requirements. Footprint does not consider a PM limit less than the Subpart IIII requirements to be an appropriate BACT.

Overall, with the elimination of a DPF on economic grounds, the review of other RBLC precedents supports the selection of Subpart IIII compliance as BACT.

1.3.4 H_2SO_4

For H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for H_2SO_4 is limiting the fuel sulfur content. Based on the selection of ULSD as the BACT fuel, this is the lowest sulfur content fuel suitable for the emergency generator.

The BACT process for H_2SO_4 proceeds directly to the selection of BACT. Footprint has based the H_2SO_4 limit on 5% molar conversion of fuel sulfur to H_2SO_4. Most of the emergency generators in Table 1-10 do not have an H_2SO_4 limit. The only numerical limits for H_2SO_4 identified for an emergency generator are those for the two recent Ohio PSD permits (Oregon and Carroll County). The limit in each case is 0.000132 grams/kWhr. Both these project are approved with ULSD as the emergency generator fuel. Conversion of the Footprint limit to grams/kWhr indicates that 5% molar conversion of the fuel sulfur to H_2SO_4 yields 0.0005 grams/kWhr, or about 4 times the Ohio limits. Review of the Ohio approvals indicates this factor is based on an EPA toxics emission factor which apparently allows for a much lower molar conversion of fuel sulfur to H_2SO_4. While this factor may be suitable for estimating actual emissions, Footprint believes this factor is not appropriate for setting an emission limit. Therefore, given that most agencies do not even regulate emergency generator H_2SO_4, Footprint believes the PSD BACT emission rate based on 5% molar conversion of fuel sulfur to H_2SO_4 is justified as BACT. This 5% molar conversion of fuel sulfur to H_2SO_4 is a reasonable upper limit permit limit assumption for fuel combustion sources that do not have an SCR or oxidation catalyst.

1.3.5 GHG

For GHG, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion controls suitable for GHG. The BACT process for GHG proceeds directly to the selection of BACT. Given that emergency generators operate so little, agencies have not required review of generator efficiency as part of GHG BACT.

With respect to GHG, most of the emergency generators listed on the RBLC with GHG limits for PSD BACT are expressed as a mass emission value, which is a project specific number reflecting the particular size and gas throughput limits of the specific project unit. Therefore, these GHG equipment-specific limits are not automatically transferrable as comparable limits for this Project. One unit listed in Table 1-10 has a lb/MMBtu limit based on ULSD corresponding to 163.6 lb CO_2e/MMBtu. For its proposed GHG limit for the emergency generator, the Project has chosen a value based on the USEPA Part 75 default emission factors (162.85 lb/MMBtu), incorporating both CO_2, CH_4, and N_2O. The Applicant proposes a GHG PSD BACT limit expressed in the units of lb/MMBtu (162.85 lb/MMBtu) as most appropriate PSD BACT limit.

1.4 Emergency Fire Pump

This section supplements the PSD BACT analysis for the emergency diesel fire pump to address public comments made on the draft permit documents. The Project is subject to PSD review for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, and thus the emergency diesel fire pump is subject to PSD BACT for these pollutants.

The Project includes a 371 hp emergency diesel fire pump that will have ultra-low sulfur diesel (ULSD) as the only fuel of use. Table 1-13 presents the proposed BACT limits for the emergency diesel fire pump for pollutants subject to PSD review.

Table 1-13. Emergency Diesel Fire Pump Proposed PSD BACT Limits

Pollutant	Emission Limitation (grams/kWhr)	Emission Limitation (grams/hphr)
NOx	4.0	3.0
$PM/PM_{10}/PM_{2.5}$	0.20	0.15
H_2SO_4	0.0003 lb/hr (0.00012 lb/MMBtu)	
GHG as CO2e	162.85 lb/MMBtu	

The proposed PSD BACT limits for NO_x and $PM/PM_{10}/PM_{2.5}$ are based on compliance with the EPA New Source Performance Standards (NSPS), 40 CFR 60 Subpart IIII. For a 371 hp fire pump engine, Subpart IIII requires what is referred to as a Tier 3 engine. For H_2SO_4, the PSD BACT limit is based on use of ultra-low sulfur diesel (ULSD) fuel, and conversion of 5% of the fuel sulfur on a molar basis to H_2SO_4. The GHG limit is based on EPA emission factors for ULSD.

In order to inform the PSD BACT process, Footprint has compiled all the PSD BACT determinations in the last five years for emergency fire pumps at new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. Table 1-14 provides this compilation. Review of Table 1-14 indicates that all emergency fire pumps are fired with ULSD. All emergency fire pumps in Table 1-14 do not have any post combustion controls for PSD pollutants. Table 1-14 will be referred to in the individual pollutant discussion below.

Table 1-14. Summary of Recent PSD BACT Determinations for Reciprocating Fire Pump Engines at Large (>100MW) Gas Fired Combined-Cycle Generating Plants for NO_x, PM, H_2SO_4, GHG

Facility	Location	Permit Date	Fire Pump Engine Size	Emission Limits[1] NOx	PM/PM10/PM2.5	H2SO4	GHG
Carroll County Energy	Washington Twp., OH	11/5/2013	400 hp	Subpart IIII		0.000132 grams/kWhr	115.75 tpy
Oregon Clean Energy	Oregon, OH	06/18/2013	300 hp	Subpart IIII		0.000132 grams/kWhr	87 tpy
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	330 hp	Subpart IIII		--	Low carbon fuel and efficient operation
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	450 hp	1.9 gm/hp-hr	0.15 grams/hp-hr	0.00012 grams/hp-hr	33.8 tpy
Brunswick County Power	Freeman, VA	03/12/2013	305 hp	Subpart IIII		ULSD	Low carbon fuel and efficient operation
Moxie Patriot LLC	Clinton Twp PA	01/31/2013	460 hp	2.6 grams/hp-hr	0.09 grams/hp-hr	--	--
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) – 371 hp	Subpart IIII		--	172 tpy
Hess Newark Energy Center	Newark, NJ	11/01/2012	270 hp	Subpart IIII		--	--
Moxie Liberty LLC	Asylum Twp PA	10/10/2012	Size not given	2.6 grams/hp-hr	0.09 grams/hp-hr	--	--
Cricket Valley	Dover, NY	09/27/2012	460 hp	Subpart IIII		--	--
ES Joslin Power	Calhoun, TX	09/12/2012	Size not given	2.08 lb/hr	0.10 lb/hr	--	--
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	270 hp	Subpart IIII		--	--
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	182 hp	Subpart IIII		--	--
Thomas C. Ferguson Power	Llano, TX	09/01/2011	617 hp	3.81 lb/hr	0.20 lb/hr	--	7,027.8 lb/hr 30 day rolling average 351.4 tpy 365 day rolling average
Entergy Nine-mile Point Unit 6	Westwego, LA	08/16/2011	350 hp	--	Subpart IIII	--	CO_2e 163.6 lb/MMBtu,
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	100 hp	5.45 gm/hp-hr	0.032 gm/hp-hr	--	--

Facility	Location	Permit Date	Fire Pump Engine Size	Emission Limits[1]			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Avenal Power Center	Avenal, CA	05/27/2011	288 hp	3.4 grams/hp-hr	ULSD	--	--
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	265	Subpart IIII		--	--
Dominion Warren County	Front Royal, VA	12/21/2010	2,3 MMBtu/hr	Subpart IIII		--	--
Pondera/King Power Station	Houston, TX	08/05/2010	Size not given	1.54 lb/hr	0.55 lb/hr	--	--
Victorville 2 Hybrid	Victorville, CA	03/11/2010	182 hp	Subpart IIII		--	--
Panda Sherman Power	Grayson, TX	02/03/2010	Size not given	7.75 lb/hr	0.55 lb/hr	--	--
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	Size not given	9.3 lb/hr	0.7 lb/hr	--	--

[1] Short term limits only for NOx, PM, and H2SO4. Limits obtained from agency permitting documents when not available in RBLC

1.4.1 Fuel Selection

Step 1: Identify Candidate Fuels

- Natural gas
- ULSD

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although use of natural gas would be unusual for an emergency fire pump engine.

Step 3: Rank Control Technologies by Control Effectiveness

Natural gas engines can achieve lower emissions compared to ULSD.

Step 4: Evaluate Controls

Normally, for an emergency fire pump, it is very important to have the fuel supply directly available without the possibility of a natural gas supply interruption making it impossible to operate the emergency fire pump in an emergency. The purpose of the emergency fire pump is to be able to pump water in the event of a fire. So in order to maintain this important emergency function, ULSD, which can be stored in a small tank adjacent to the emergency fire pump, is the fuel of choice.

Step 5: Select BACT

ULSD is proposed as the BACT fuel for the Project emergency fire pump.

1.4.2 NO_x

Step 1: Identify Candidate Control Technologies

- Selective Catalytic Reduction
- Low NOx engine design in accordance with EPA NSPS, 40 CFR 60 Subpart IIII (Tier 3 engine for 371 hp fire pump unit)

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although application of SCR is unusual for an emergency fire pump.

Step 3: Rank Control Technologies by Control Effectiveness

SCR can normally achieve 90% remove of NO_x emissions, so it is more effective than the Tier 3 engine design which is based on low-NO_x engine design. However, for an emergency fire pump, if this unit is used just for short period of test and facility shutdown in an actual emergency, the ability of the SCR to control emissions will be significantly reduced since the engine/SCR takes time to warm up to achieve good NOx control.

Step 4: Evaluate Controls

Since SCR is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 1-15. The capital cost estimate for an SCR system is based on information provided by Milton Cat Power Systems. The other factors are from the OAQPS Cost Control Manual. The SCR has been conservatively assumed to control 90% of the potential NO_x emissions even though this is unlikely in this application. Table 1-15 indicates that the cost effectiveness of an SCR is over \$90,000 per ton of NO_x. This cost is excessive, even if the emergency fire pump runs the maximum allowable amount of 300 hours per year (unlikely) and 90% NO_x control of the full potential to emit is achieved.

There are no energy or environmental issues with a Tier 3 fire pump that would indicate selection of SCR as BACT, given the unfavorable SCR economics.

Step 5: Select BACT

With respect to the selection of a PSD BACT for NO_x for the emergency fire pump, Table 1-14 indicates that compliance with Subpart IIII is the most common limit. Several BACT determinations contain gram/kWhr or gram/hp-hr limits that approximate the Subpart IIII values but do not specifically reference Subpart IIII. Several Texas projects have lb/hr limits but do not provide the engine size to determine limits per unit of output.

With the elimination of SCR on economic grounds, the review of other RBLC precedents supports the selection of Subpart IIII compliance as BACT.

1.4.3 PM/PM_{10}/$PM_{2.5}$

Step 1: Identify Candidate Control Technologies

- Active Diesel Particulate Filter (DPF)
- Low PM engine design in accordance with EPA NSPS, 40 CFR 60 Subpart IIII (Tier 3 engine for 371 hp unit)

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although application of a DPF is unusual for an emergency engine.

Step 3: Rank Control Technologies by Control Effectiveness

An active DPF can achieve up to 85% particulate removal (CARB Level 3), so it is more effective than the Tier 3 engine design which is based on low-emission engine design.

Step 4: Evaluate Controls

Since a DPF is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 1-16. The capital cost estimate for an active system is based on information provided by Milton Cat Power Systems. The other factors are from the OAQPS Cost Control Manual. Table 1-16 indicates that the cost effectiveness of an active DPF is over \$1,000,000 per ton of PM/PM_{10}/$PM_{2.5}$. This cost is excessive, even if the emergency fire pump runs the maximum allowable amount of 300 hours per year (unlikely)

TABLE 1-15 371 HP EMERGENCY FIRE PUMP
ECONOMIC ANALYSIS - SELECTIVE CATALYTIC REDUCTION -

BACT Assessment
Control System Life: 10 years
Interest Rate: 10.00%
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) 0.163

Baseline NOx Emissions per 40 CFR 60 Subpart IIII (tpy) 0.37
SCR Control Efficiency (%) 90%

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estmate (per Milton Cat)		$85,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$4,250
Total Equipment Cost (TEC)			**$89,250**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$7,140
b.	Erection and Handling	(TEC*0.14)	$12,495
c.	Electrical	(TEC*0.04)	$3,570
d.	Piping	(TEC*0.02)	$1,785
e.	Insulation	(TEC*0.01)	$893
f.	Painting	(TEC*0.01)	$893
Total Direct Installation Cost			**$26,775**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$8,925.00
b.	Construction/Field Expenses	(TEC*0.05)	$4,463
c.	Construction Fee	(TEC*0.1)	$8,925
d.	Start up	(TEC*0.02)	$1,785
e.	Performance Test	(TEC*0.01)	$893
Total Indirect Installation Cost			**$24,990**
Total Capital Cost (TCC)			**$141,015**

Capital Recovery		**$22,985**
Direct Operating Costs		
a.	Ammonia	$477
b	Operating Labor (OL):(0.5 hr/shift)($25.6/hr)	$480
c.	Maintenance Labor (ML):(0.5 hr/shift)($25.6/hr)	$480
d	Maintenance Materials = Maintenance Labor	$480
Total Direct Operating Cost		**$1,440**
Catalyst Replacement is not included since the emergency fire pump will only operate a maximum of 300 hours in any year		
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$576
b.	Property Tax: (TCC*0.01)	$1,410
c.	Insurance: (TCC*0.01)	$1,410
d.	Administration: (TCC*0.02)	$2,820
Total Indirect Operating Cost		**$6,216**
Total Annual Cost		**$30,641**
NOx Reduction (tons/yr)		**0.33**
Cost of Control ($/ton - NOx)		**$92,502**

Note 1: Ammonia cost based on estimated as delivered cost for 19% aqueous ammonia of $0.60 per pound of ammonia, and 1.2 lbs of NH3 injected per pound of NOx removed

TABLE 1-16 371 HP EMERGENCY DIESEL FIRE PUMP
ECONOMIC ANALYSIS - ACTIVE DIESEL PARTICULATE FILTER

BACT Assessment
Control System Life: 10 years
Interest Rate: 10.00%
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) 0.163

Baseline PM Emissions per 40 CFR 60 Subpart IIII (tpy) 0.018
DPF Control Efficiency (%) 85%

Equipment Cost (EC)		(Factor)	
a.	DPF Capital Cost Estmate		$45,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$2,250
Total Equipment Cost (TEC)			**$47,250**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$3,780
b.	Erection and Handling	(TEC*0.14)	$6,615
c.	Electrical	(TEC*0.04)	$1,890
d.	Piping	(TEC*0.02)	$945
e.	Insulation	(TEC*0.01)	$473
f.	Painting	(TEC*0.01)	$473
Total Direct Installation Cost			**$14,175**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$4,725.00
b.	Construction/Field Expenses	(TEC*0.05)	$2,363
c.	Construction Fee	(TEC*0.1)	$4,725
d.	Start up	(TEC*0.02)	$945
e.	Performance Test	(TEC*0.01)	$473
Total Indirect Installation Cost			**$13,230**
Total Capital Cost (TCC)			**$74,655**

Capital Recovery		**$12,169**
Direct Operating Costs		
a	Operating Labor (OL):(0.25 hr/shift)($25.6/hr)	$240
b	Maintenance Labor (ML):(0.25 hr/shift)($25.6/hr)	$240
c.	Maintenance Materials = Maintenance Labor	$240
Total Direct Operating Cost		**$720**
DPF Replacement is not included since the emergency fire pump will only operate a maximum of 300 hours in any year		
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$288
b.	Property Tax: (TCC*0.01)	$747
c.	Insurance: (TCC*0.01)	$747
d.	Administration: (TCC*0.02)	$1,493
Total Indirect Operating Cost		**$3,275**
Total Annual Cost		$16,164
PM Reduction (tons/yr)		0.02
Cost of Control ($/ton - PM)		$1,033,319

There are no energy or environmental issues with a Tier 3 fire pump that would indicate selection of a DPF as BACT, given the unfavorable economics.

Step 5: Select BACT

With respect to the selection of a PSD BACT for $PM/PM_{10}/PM_{2.5}$ for the emergency fire pump, Table 1-14 indicates that compliance with Subpart IIII is the most common limit. There are two BACT determinations for PA project (Moxie projects) that both have very low $PM/PM_{10}/PM_{2.5}$ limits of 0.02 gram/hp-hr. Footprint suspects that this limit is a mistaken entry for the Subpart IIII value of 0.2 grams/kWhr. Several Texas projects have lb/hr limits but do not provide the engine size to determine limits per unit of output. Brockton (MA) also has a very low PM limit, much lower than the Subpart IIII requirements. Footprint does not consider a PM limit less than the Subpart IIII requirements to be an appropriate BACT.

With the elimination of a DPF on economic grounds, the review of other RBLC precedents supports the selection of Subpart IIII compliance as BACT.

1.4.4 H_2SO_4

For H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for H_2SO_4 is limiting the fuel sulfur content. Based on the selection of ULSD as the BACT fuel, this is the lowest sulfur content fuel suitable for the emergency fire pump.

The BACT process for H_2SO_4 proceeds directly to the selection of BACT. Footprint has based the H_2SO_4 limit on 5% molar conversion of fuel sulfur to H_2SO_4. Most of the emergency fire pumps in Table 1-14 do not have an H_2SO_4 limit. The only numerical limits for H_2SO_4 identified for an emergency fire pump are those for the two recent Ohio PSD permits (Oregon and Carroll County), and the Hickory Run (PA) project. The limit for the Ohio cases is 0.000132 grams/kWhr, and for Hickory Run is 0.00012 grams/hp-hr (0.00016 grams/kW-hr). All these projects are approved with ULSD as the emergency fire pump fuel. Conversion of the Footprint limit to grams/kWhr indicates that 5% molar conversion of the fuel sulfur to H_2SO_4 yields 0.0005 grams/kWhr, or about 4 times the Ohio limits and three times the Hickory Run limit. Review of the Ohio approvals indicates this factor is based on an EPA toxics emission factor which apparently allows for a much lower molar conversion of fuel sulfur to H_2SO_4. While this factor may be suitable for actual emissions, Footprint believes this factor is not appropriate for setting an emission limit. Therefore, given that most agencies do not even regulate emergency fire pump H_2SO_4, Footprint believes the PSD BACT emission rate based on 5% molar conversion of fuel sulfur to H_2SO_4 is justified as BACT. As noted above for the emergency diesel generator, this 5% molar conversion of fuel sulfur to H_2SO_4 is a reasonable upper limit permit limit assumption for fuel combustion sources that do not have an SCR or oxidation catalyst.

1.4.5 GHG

For GHG, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion controls suitable for GHG. The BACT process for GHG proceeds directly to the selection of BACT. Given that emergency fire pumps operate so little, agencies have not required review of fire pump efficiency as part of GHG BACT.

With respect to GHG, most of the emergency pumps listed on the RBLC with GHG limits for PSD BACT are expressed as a mass emission value, which is a project specific number reflecting the particular size and gas throughput limits of the specific project unit. Therefore, these GHG equipment-specific limits are not automatically transferrable as comparable limits for this Project. One unit listed in Table 1-14 has a lb/MMBtu limit based on ULSD corresponding to 163.6 lb CO_2e/MMBtu. For its proposed GHG limit for the emergency pumps, the Project has chosen a value based on the USEPA Part 75 default emission factors (162.85 lb/MMBtu), incorporating both CO_2, CH_4, and N_2O. The Applicant proposes a GHG PSD BACT limit expressed in the units of lb/MMBtu (162.85 lb/MMBtu) as most appropriate PSD BACT limit.

1.5 Auxiliary Cooling Tower

This section provides a PSD BACT analysis for the auxiliary mechanical draft cooling tower. The primary function for the auxiliary cooling tower is to provide necessary equipment cooling for the gas turbine itself, which is not possible to provide using the Air Cooled Condenser (ACC) used to condense steam discharged from steam turbines. The auxiliary mechanical draft cooling tower planned for use is a 3-cell commercial scale tower, with a total circulating water flow (all 3 cells) of 13,000 gallons per minute (gpm).

In general, mechanical draft cooling towers provide cooling of the circulating water by spraying (warm) circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air being drawn in through the sides of the tower towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water may be entrained into this air flow. These droplets of circulating water contain dissolved solids. Specially designed drift eliminators are typically located above the water sprays to remove most of these droplets and return them to the fill. But a small fraction of these droplets can escape into the fan discharge into the atmosphere. These droplets then evaporate, and the particulates in these droplets are a source of particulate ($PM/PM_{10}/PM_{2.5}$) emissions. $PM/PM_{10}/PM_{2.5}$ are the only PSD pollutants emitted from the auxiliary cooling tower.

The Footprint auxiliary cooling tower is being designed to limit the drift rate to 0.001% of the circulating water flow (0.13 gpm). The design dissolved solids concentration for the circulating water is 1,500 milligrams per liter (mg/l) As documented in Appendix B of the December 2012 PSD Application, Calculation Sheet 6, the potential PM/PM_{10} emissions from the auxiliary cooling tower are 0.43 tpy, and the potential $PM_{2.5}$ emissions are 0.17 tpy.

Step 1: Identify Candidate Technologies

Particulate control technologies identified for cooling towers at new large > 100 MW combined cycle turbines are as follows:

- Air-Cooled Condensers (ACCs): This eliminates the use of circulating water for cooling and thus eliminates drift for large towers used for steam turbine condenser cooling
- High efficiency cooling tower drift eliminators.
- Reduction in the dissolved solids concentration in circulating water.

Step 2: Eliminate Infeasible Technologies

ACCs are technically feasible for steam turbine condenser cooling large combined cycle units. However, use of an ACC is not technically feasible for the auxiliary equipment cooling required for a GE Frame 7FA.05 combustion turbines since ACCs cannot achieve the degree of cooling performance required. High efficiency cooling tower drift eliminators are also technically feasible for mechanical draft cooling towers. The total dissolved solids concentration (TDS) in circulating water is a function of the makeup water TDS, which depends on the makeup water source, and the TDS at which the tower is operated. Removing TDS from the makeup water is considered technically infeasible for a small auxiliary mechanical draft cooling tower. However, the TDS in the circulating water can be decreased by increasing the amount of "blowdown" from the tower. Blowdown is a stream of wastewater continuously discharged from the tower to remove TDS from the circulating water. Increasing blowdown reduces the TDS and is technically feasible.

Step 3: Rank Control Technologies by Control Effectiveness

The ranking of the technically feasible technologies is as follows:

1. High efficiency cooling tower drift eliminators: Generally recognized to be capable of achieving a drift rate of 0.0005% of circulating water flow for large cooling tower used for power plant steam turbine condenser cooling. However, for small commercial mechanical draft cooling towers being used in this application, the standard design is for 0.001% drift.
2. Reduce the TDS in circulating water: Mechanical draft cooling towers are operated with circulating water TDS as low as 1000 milligrams/liter (mg/l).

Step 4: Evaluate Controls

Footprint has compiled all the PSD BACT determinations in the last five years for mechanical draft cooling towers at new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. Table 1-17 provides this compilation.

Review of Table 1-17 indicates that the available cooling tower BACT determinations are almost exclusively for large towers used for steam turbine condenser cooling. These towers are commonly specified for 0.0005% drift. Texas project determinations typically do not have the size of the tower indicated, and only have lb/hr emissions indicated which does not provide a meaningful comparison.

The smallest tower identified with a PM PSD BACT determination is the 12,000 gpm chiller tower at the Entergy Ninemile Point project in Louisiana. This tower in fact has drift specified at 0.001%, which agrees with our finding that small towers are designed for 0.001% drift. Therefore, it is concluded that 0.001% drift is justified as BACT for the small auxiliary mechanical draft cooling tower for Footprint. All towers identified with drift limits of 0.0005% are significantly larger than the Footprint auxiliary tower.

With respect to the circulating water total dissolved solids (TDS) concentration, for projects where this value is identified, these values range from 1000 to 6200 mg/l. Only two projects have design values < Footprint's 1500 mg/l. A collateral environmental impact of increasing the blowdown to decrease TDS is increasing consumption of water. Footprint has selected 1500 mg/l as a reasonable TDS value balance to drift emissions and water conservation.

Step 5: Select BACT

The Footprint Project will meet 0.001% drift and limit the potential PM/PM_{10} emissions from the auxiliary cooling tower to 0.43 tpy, and the potential $PM_{2.5}$ emissions to 0.17 tpy. These values are justified as BACT.

Table 1-17. Summary of Recent Cooling Tower Particulate BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Cooling Tower Description (total circulating water flow rate in gallons per minute unless otherwise specified)	BACT[1] $PM/PM_{10}/PM_{2.5}$
Renaissance Power	Carson City, MI	11/1/2013	10 cell tower	0.0005% drift
Langley Gulch Power	Payette, ID	08/14/2013	76,151 gpm	Drift Eliminators (not limit specified); 5000 mg/l
Oregon Clean Energy	Oregon, OH	06/18/2013	322,000 gpm	0.0005% drift; 2030.5 mg/l
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	187,400 gpm	0.0005% drift; 5000 mg/l
Brunswick County Power	Freeman, VA	03/12/2013	46,000 gpm (towers for turbine inlet air chillers)	0.0005% drift; 1000 mg/l
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	2 towers at 170,000 gpm each	0.0005% drift
Hess Newark Energy	Newark, NJ	11/01/2012	220,870 gpm	0.0005% drift; 4150 mg/l
Channel Energy Center, LLC	Houston, TX	10/15/2012	Size not specified	1.33 lb/hr PM_{10}
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	Full wet cooling for 431 MW combined cycle facility – circulating flow not given	0.0005% drift
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	Cooling tower size not specified	PM –3.13 lb/hr $PM_{10}/PM_{2.5}$ 1.75lb/hr
Entergy Ninemile Point Unit 6	Westwego, LA	08/16/2011	Chiller cooling tower 12,000 gpm Unit 6 cooling tower 115,847 gpm	Chiller cooling tower 0.001% drift Unit 6 cooling tower 0.0005% drift
Brockton Power	Brockton MA	7/20/2011	92,500 gpm	0.0005% drift; 3235 mg/l
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	Cooling tower circulating water flow rate 85,000 gpm	0.0005% drift; 1200 mg/l
Pondera/King Power Station	Houston, TX	08/05/2010	2 towers - size not specified	1.28 lb/hr/tower
Victorville 2 Hybrid	Victorville, CA	03/11/2010	130,000 gpm	0.0005% drift; 5000 mg/l
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	Cooling tower size not specified	0.0005% drift
Russell Energy Center	Hayward, CA	02/03/2010	141,352 gpm	0.0005% drift; 6200 mg/l
Panda Sherman Power	Grayson, TX	02/03/2010	Cooling tower sizes not specified	Main tower 4.68 lb/hr PM, inlet air chiller tower 0.27 lb/hr PM Both 0.0005% drift
Lamar Power Partners II LLC	Paris, TX	06/22/2009	Cooling tower size not specified	2.4 lb/hr PM_{10}
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	4 towers - size not specified	1.0 lb/hr/tower PM 0.3 lb/hr/tower PM_{10}

[1]Mass emissions (lb/hr) are only specified if comparable units across projects (% drift, total dissolved solids) are not provided.

Appendix A

Updates to Footprint Air Emissions Calculations

Updated GE performance data is provided as Attachment A-1 (3 sheets). These sheets update the performance data previously provided.

Items that have changed subsequent to the public review drafts issued by MassDEP are highlighted in yellow on all the sheets that are updates of prior sheets.

Calculation Sheet 1 presents the potential to emit (PTE) calculations for one turbine. Two operating cases are used to calculate potential emissions (PTE) are 100% load at 50 °F for baseload operation (8,040 hours/year) and 100% load at 90 °F with the duct burners and evaporative coolers on (720 hours per year). GE Case 7 is 100% load at 50 °F, with a heat input of 2,130 MMBtu/hr. GE Case 12 is 100% load at 90 °F with the duct burners and evaporative coolers on with a heat input of 2,449 MMBtu/hr. The PTE values are based on the direct calculation with the exact lb/MMBtu values shown on Calculation Sheet 1.

For CO, Calculation Sheet 1 shows the PTE based on 8,760 hours of operation, but the worst case PTE is based on separate calculations using startup and shutdown (SUSD) emissions and an assumed operating scenario. These calculations are provided on Calculation Sheet 2 for GE and reflect a higher PTE for CO compared to those in Calculation Sheet 1. Therefore, the maximum SUSD scenario value for CO PTE is used. Calculation Sheet 1 shows the revised emissions for CO for both the turbine (based on a maximum rate of 8.0 lb/hr/turbine) and the auxiliary boiler with the CO catalyst. The auxiliary boiler CO emission rate with the oxidation catalyst is 10% of the prior rate (0.035 lb/MMBtu)(0.10) = 0.0035 lb/MMBtu.

Calculation Sheet 3 in the December 21, 2012 application had been for Siemens SUSD and is now dropped. Calculation Sheets 4, 5, and 6 presented emission calculations for the emergency generator, emergency diesel fire pump, and auxiliary cooling tower respectively. These have not changed and are not repeated here.

Calculation Sheet 7 presents the updated overall summary of potential-to-emit (PTE) for the facility.

Calculation Sheets 8 and 9 are new, and are the NO_x BACT cost spreadsheets for the auxiliary boiler, supporting the values in Table 1-8.

Attachment A-1 (Sheet 1 of 3)

GE Energy 107F Series 5 Rapid Response Combined Cycle Plant - Emissions Data - Natural Gas

GE Energy Performance Data - Site Conditions

Operating Point		1	2	3	4	5	6	7	8	9	10	11	12	13
Case Description		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	50% DB firing	100% DB firing	Unfired
Ambient Temperature	°F	0	0	0	20	20	20	50	50	50	90	90	90	90
Ambient Pressure	psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Relative Humidity	%	60	60	60	60	60	60	60	60	60	60	60	60	60

GE Energy Performance Data - Plant Status

HRSG Duct Burner (On/Off)		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Fired	Fired	Unfired
Evaporative Cooler state (On/Off)		Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	Off
Gas Turbine Load	%	BASE	75%	50%	BASE	75%	46%	BASE	75%	46%	BASE	PEAK	PEAK	BASE
Gas Turbines Operating		1	1	1	1	1	1	1	1	1	1	1	1	1

GE Energy Performance Data - Fuel Data

GT Heat Consumption	MMBtu/hr	2300	1850	1460	2250	1790	1360	2130	1700	1310	2040	2082	2082	1980
Duct Burner Heat Consumption	MMBtu/hr	0	0	0	0	0	0	0	0	0	0	183	367	0
Total (GT + DB)	MMBtu/hr	2300	1850	1460	2250	1790	1360	2130	1700	1310	2040	2265	2449	1980

GE Energy Performance Data - HRSG Exit Exhaust Gas Emissions

NOx	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2	2
CO	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2	2
VOC	ppmvdc	1	1	1	1	1	1	1	1	1	1	2	2	1
NH3	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2	2

NOx	lb/MMBtu	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074
CO	lb/MMBtu	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045
VOC	lb/MMBtu	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0022	0.0022	0.0013
NH3	lb/MMBtu	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027
Particulates - Filterable + Condensible, Including Sulfates	lb/MMBtu	0.0038	0.0048	0.0060	0.0039	0.0049	0.0065	0.0041	0.0052	0.0067	0.0043	0.0057	0.0053	0.0044

NOx	lb/hr	17.0	13.7	10.8	16.7	13.2	10.1	15.8	12.6	9.7	15.1	16.8	18.1	14.7
CO	lb/hr	8.0	8.0	6.6	8.0	8.0	6.1	8.0	7.7	5.9	8.0	8.0	8.0	8.0
VOC	lb/hr	3.0	2.4	1.9	2.9	2.3	1.8	2.8	2.2	1.7	2.7	5.0	5.4	2.6
NH3	lb/hr	6.2	5.0	3.9	6.1	4.8	3.7	5.8	4.6	3.5	5.5	6.1	6.6	5.3
Particulates - Filterable + Condensible, Including Sulfates	lb/hr	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	13.0	13.0	8.8

ppmvdc is parts per million by volume, dry basis, corrected to 15% O2
MMBtu is on a Higher Heating Value (HHV) basis

Attachment A-1 (Sheet 2 of 3)

GE Energy 107F Series 5 Rapid Response Combined Cycle Plant - Emission Data - Natural Gas

GE Energy Performance Data - Site Conditions

Operating Point		14	15	16	17	18	19	20	21	22	23	24	25
Case Description		50% DB firing	100% DB firing	Unfired	Unfired	Unfired	50% DB firing	100% DB firing	Unfired	50% DB firing	100% DB firing	Unfired	Unfired
Ambient Temperature	°F	90	90	90	90	105	105	105	105	105	105	105	105
Ambient Pressure	psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Relative Humidity	%	60	60	60	60	50	50	50	50	50	50	50	50

GE Energy Performance Data - Plant Status

HRSG Duct Burner (On/Off)		Fired	Fired	Unfired	Unfired	Unfired	Fired	Fired	Unfired	Fired	Fired	Unfired	Unfired
Evaporative Cooler state (On/Off)		Off	Off	Off	Off	On	On	On	Off	Off	Off	Off	Off
Gas Turbine Load	%	PEAK	PEAK	75%	47%	BASE	PEAK	PEAK	BASE	PEAK	PEAK	75%	49%
Gas Turbines Operating		1	1	1	1	1	1	1	1	1	1	1	1

GE Energy Performance Data - Fuel Data

GT Heat Consumption	MMBtu/hr	2017	2017	1590	1260	1990	2005	2005	1880	1928	1928	1520	1240
Duct Burner Heat Consumption	MMBtu/hr	183	377	0	0	0	183	377	0	183	377	0	0
Total Heat Consumption (GT + DI	MMBtu/hr	2201	2394	1590	1260	1990	2188	2382	1880	2112	2305	1520	1240

GE Energy Performance Data - HRSG Exit Exhaust Gas Emissions

NOx	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2
CO	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2
VOC	ppmvdc	1.7	1.7	1	1	1	1.7	1.7	1	1.7	1.7	1	1
NH3	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2
NOx	lb/MMBtu	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074
CO	lb/MMBtu	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045
VOC	lb/MMBtu	0.0022	0.0022	0.0013	0.0013	0.0013	0.0022	0.0022	0.0013	0.0022	0.0022	0.0013	0.0013
NH3	lb/MMBtu	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027
Particulates - Filterable + Condensible, Including Sulfates	lb/MMBtu	0.0059	0.0054	0.0055	0.0070	0.0044	0.0059	0.0055	0.0047	0.0062	0.0056	0.0058	0.0071

NOx	lb/hr	16.3	17.7	11.8	9.3	14.7	16.2	17.6	13.9	15.6	17.1	11.2	9.2
CO	lb/hr	8.0	8.0	7.2	5.7	8.0	8.0	8.0	8.0	8.0	8.0	6.8	5.6
VOC	lb/hr	4.8	5.3	2.1	1.6	2.6	4.8	5.2	2.4	4.6	5.1	2.0	1.6
NH3	lb/hr	5.9	6.5	4.3	3.4	5.4	5.9	6.4	5.1	5.7	6.2	4.1	3.3
Particulates - Filterable + Condensible, Including Sulfates	lb/hr	13.0	13.0	8.8	8.8	8.8	13.0	13.0	8.8	13.0	13.0	8.8	8.8

ppmvdc is parts per million by volume, dry basis, corrected to 15% O2
MMBtu is on a Higher Heating Value (HHV) basis

Attachment A-1 (Sheet 3 of 3)

GE Energy 107FA.05 Rapid Response Combined Cycle Plant
Manufacturer's Emissions Data - Natural Gas - Startup and Shutdown Conditions - Single Unit Basis

	NOx (lb)	CO (lb)	VOC (lb)	PM10 (lb)	Duration (min)
Cold Start (GT Fire to HRSG Stack Emissions Compliance with Base Load Hold)	89	285	23	7.3	45
Warm Start (GT Fire to HRSG Stack Emissions Compliance with Base Load Hold)	54	129	13	5.0	32
Hot Start (GT Fire to HRSG Stack Emissions Compliance with Base Load Hold)	28	121	12	2.6	18
Shutdown (HRSG Stack EC to GT Flame Off)	10	151	29	5.8	27

Calculation Sheet 1
Annual Potential Emissions for Combustion Turbines and Auxiliary Boiler

	One Combustion Turbine at 100% Load			Auxiliary Boiler	
	50 deg F	90 deg F	Annual	Gas	Annual
	No DF	DF, EC	tpy	lb/MMBtu	tpy
Hours per Year	8040	720		6570 (FLE)	6570 (FLE)
MMBtu/hr	2130	2449		80	
NOx (lb/MMBtu)	0.0074	0.0074	69.9	0.011	2.9
CO	8.0 lb/hr		35.0	0.0035	0.9
VOC (lb/MMBtu)	0.0013	0.0022	13.1	0.005	1.3
SO2 (lb/MMBtu)	0.0015	0.0015	14.2	0.0015	0.4
PM/PM-10/PM-2.5	8.8 lb/hr	13.0 lb/hr	40.1	0.005	1.3
NH3 (lb/MMBtu)	0.0027	0.0027	25.5	--	--
H2SO4 (lb/MMBtu)	0.001	0.001	9.4	0.0009	0.24
Lead (lb/MMBtu)	--	--	--	4.90E-07	0.00013
Formaldehyde (lb/MMBtu)	0.00035	0.00035	3.3	7.40E-05	0.019
Total HAP (lb/MMBtu)	0.000667	0.000667	6.3	1.90E-03	0.5
CO2 (lb/MMBtu)	118.9	118.9	1,122,920	118.9	31,247
CO2e (lb/MMBtu)	119.0	119.0	1,124,003	119.0	31,277

Notes:

1. DF = Duct Firing
2. EC = Evaporative Coolers
3. FLE = Full Load Equivalent
4. Annual potential emissions per turbine for all pollutants except CO and PM are based on [(2130 MMBtu/hr)(lb/MMBtu no DF)(8040 hrs)+(2449 MMBtu/hr)(lb/MMBtu DF)(720 hrs)]/2000 lb/ton
5. Annual potential emissions shown here per turbine for CO are based on 8 lb/hr for 8760 hours. However, the worst case PTE for CO includes the startup/shutdown scenario as shown in Calculation Sheet 2.
6. Annual potential emissions per turbine for PM/PM-10/PM-2.5 are based on [(8.8 lb/hr)(8040 hrs) + (13.0 lb/hr)(720 hrs)]/2000 lb/ton
7. H2SO4 emissions for the aux boiler are based on 40% molar conversion of fuel sulfur to H2SO4 Correcting for molecular weight, the H2SO4 emission rate is: (0.0015 lb SO2/MMBtu)(0.4)(98 lb/mole H2SO4)/(64 lb/mole SO2) = 0.0009 lb/MMBtu
8. Annual potential emissions for the aux boiler are based on: (80 MMBtu/hr)(lb/MMBtu)(6570 hours FLE)/(2000 lb/ton)

Calculation Sheet 2
GE Emissions for CO and VOC Including Startup Shutdown Scenario

Emissions for Normal Load Cases	MMBtu/hr	CO (lb/hr)	VOC (lb/hr)
Spring/Fall Normal Load Case 7 (50 deg)	**2130**	8.0	2.8
Summaer Case 13 except for 720 hours	**1980**	8.0	2.6
Summer Case 12 for 720 hours (90 deg)	**2449**	8.0	5.4
Winter Case 4 (20 deg)	**2250**	8.0	2.9

	ASSUMED OPERATING SCENARIOS											**GE STARTUP/SHUTDOWN EMISSIONS**								
	Assumed Operating Profile Normal Loads					**starts/wk**			**starts/yr**			**CO**			**VOC**			**Normal Load Cases Emissions for Each Season**	
	days/ week	**hrs/ day**	**hrs/ week**	**Weeks/ yr**	**hrs/yr**	**cold**	**warm**	**hot**	**cold**	**warm**	**hot**	**cold**	**warm**	**hot**	**cold**	**warm**	**hot**		
	Combined startup/shutdown pounds of emissions per single event											***436***	***280***	***272***	***52***	***42***	***41***		
												Annual SUSD emissions for each category and season (lbs)							
Spring/Fall	5	12	60	20	1200	0.25	4.75	0	5	95	0	2180	26600	0	260	3990	0		
																	Case 7	9600	3323
Summer	7	24	168	2	336	0	2	0	0	4	0	0	1120	0	0	168	0		
	5	16	80	8	640	0	5	0	0	40	0	0	11200	0	0	1680	0		
	5	12	60	2	120	0	5	0	0	10	0	0	2800	0	0	420	0		
					1096												Case 13	3008	968
																	Case 12	5760	3879
Winter	7	24	168	2	336	0	1	0	0	2	0	0	560	0	0	84	0		
	5	16	80	8	640	0.25	4.75	0	2	38	0	872	10640	0	104	1596	0		
					976												Case 4	7808	2855
TOTAL RUN HRS				42	**3272**														
Planned outage	7	24	168	4	**672**				6			2616	0	0	312	0	0		
Not Dispatched (includes time in SUSD)					**4457**														
Unplanned FO	4.1%				**359**						4			1088			164		
ANNUAL HRS					**8760**														
Total Tons in Each Category													**29.8**			**4.4**		**13.1**	**5.5**
																		CO	**VOC**
																	Total Emissions per unit	**42.9**	**9.9**

Note: The startup/shutdown cycling scenario is no longer controlling for annual VOC emissions.

Calculation Sheet 7
Summary of Facility Potential to Emit (PTE) in tons per year (tpy)

	Annual emissions, tons/year						
Pollutant	**CT Unit 1 (GT + DB)**	**CT Unit 2 (GT + DB)**	**Aux Boiler**	**Emergency Generator**	**Fire Pump**	**Aux Cooling Tower**	**Facility Totals**
NO_x	69.9	69.9	2.9	1.7	0.4	0	144.8
CO	42.9	42.9	0.9	1.0	0.3	0	88.0
VOC	13.1	13.1	1.3	0.35	0.12	0	28.0
SO_2	14.2	14.2	0.4	0.0017	0.0006	0	28.8
PM_{10}	40.1	40.1	1.3	0.1	0.0	0.4	82.0
$PM_{2.5}$	40.1	40.1	1.3	0.1	0.0	0.2	81.8
NH_3	25.5	25.5	0	0	0	0	51.0
H_2SO_4 mist	9.4	9.4	0.24	1.33E-04	4.84E-05	0	19.0
Lead	0	0	0.00013	8.54E-07	3.10E-07	0	0.00013
Formaldehyde	3.3	3.3	0.019	8.76E-05	4.76E-04	0	6.6
Total HAP	6.3	6.3	0.5	1.76E-03	1.57E-03	0	13.1
CO_2	1,122,920	1,122,920	31247	180	66	0	2,277,333
CO_2e	1,124,003	1,124,003	31277	181	66	0	2,279,530

.

Calculation Sheet 8

80 MMBtu/hr Auxiliary Boiler
ECONOMIC ANALYSIS - SELECTIVE CATALYTIC REDUCTION

BACT Assessment
Control System Life: 10 years
Interest Rate: 10.00%
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF): 0.163

Baseline Emissions at 30 ppmvdc corrected to 3% O2 (tpy): 9.46
SCR Emissions at 3 ppmvdc corrected to 3% O2 (tpy): 0.95

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estimate (Cleaver Brooks)		$250,000
b	Taxes and Freight	(EC*0.05)	$12,500
Total Equipment Cost (TEC)			**$262,500**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$21,000
b.	Erection and Handling	(TEC*0.14)	$36,750
c.	Electrical	(TEC*0.04)	$10,500
d.	Piping	(TEC*0.02)	$5,250
e.	Insulation	(TEC*0.01)	$2,625
f.	Painting	(TEC*0.01)	$2,625
Total Direct Installation Cost			**$78,750**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$26,250
b.	Construction/Field Expenses	(TEC*0.05)	$13,125
c.	Construction Fee	(TEC*0.1)	$26,250
d.	Start up	(TEC*0.02)	$5,250
e.	Performance Test	(TEC*0.01)	$2,625
Total Indirect Installation Cost			**$73,500**
Total Capital Cost (TCC)			**$414,750**

Capital Recovery		**$67,604**
Direct Operating Costs		
a.	Ammonia	$12,261
b.	Operating Labor (OL):(0.5 hr/shift)($25.6/hr)	$10,512
c.	Maintenance Labor (ML):(0.5 hr/shift)($25.6/hr)	$10,512
d.	Maintenance Material = Maintenance Labor	$10,512
Total Direct Operating Cost		**$43,797**
Catalyst Replacement		
a.	33% of TEC required at year 3.33 and year 6.67, plus erection and indirect costs (0.25 of replacement)	
b.	10-year annualized cost for catalyst replacement	**$22,062**
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$12,614
b.	Property Tax: (TCC*0.01)	$4,148
c.	Insurance: (TCC*0.01)	$4,148
d.	Administration: (TCC*0.02)	$8,295
Total Indirect Operating Cost		**$29,205**
Total Annual Cost		**$162,668**
NOx Reduction (tons/yr)		**8.51**
Cost of Control ($/ton - NOx)		**$19,115**

Note 1: Ammonia cost based on estimated as delivered cost for 19% aqueous ammonia of $0.60 per pound of ammonia, and 1.2 lbs of NH3 injected per pound of NOx removed

Calculation Sheet 9

80 MMBtu/hr Auxiliary Boiler
ECONOMIC ANALYSIS - ULTRA LOW NOx (ULN) BURNER COMPARED TO STANDARD LOW NOx BURNER

BACT Assessment						
Control System Life:		10 years				
Interest Rate:		10.00%		Baseline Emissions at 30 ppmvdc corrected to 3% O2 (tpy)		9.46
Economic Factors from MassDEP Form BWP-AQ-BACT				Controlled Emissions at 9 ppmvdc corrected to 3% O2 (tpy)		2.89
Capital Recovery Factor (CRF)		0.163				
Equipment Cost (EC)		(Factor)		**Capital Recovery**		**$21,907**
a.	Capital Cost Estimate (Differential Cost of ULN compared to standard low NOx burner)		$100,000			
	(per Cleaver Brooks)			**Direct Operating Costs**		
b	Taxes and Freight	(EC*0.05)	$5,000			
				Direct Operating Costs are assumed to be the same for ULN compared to standard low-NOx burner		
Total Equipment Cost (TEC)			**$105,000**			
Direct Installation Costs						
Direct Installation Costs are assumed to be the same for ULN compared to standard low-NOx burner				**Indirect Operating Costs (based on differential cost)**		
Indirect Installation Costs (based on differential cost)				a.	Overhead (60% of OL+ML)	$0
				b.	Property Tax: (TCC*0.01)	$1,344
a.	Engineering and Supervision	(TEC*0.1)	$10,500	c.	Insurance: (TCC*0.01)	$1,344
b.	Construction/Field Expenses	(TEC*0.05)	$5,250	d.	Administration: (TCC*0.02)	$2,688
c.	Construction Fee	(TEC*0.1)	$10,500			
d.	Start up	(TEC*0.02)	$2,100	**Total Indirect Operating Cost**		**$5,376**
e.	Performance Test	(TEC*0.01)	$1,050			
Total Indirect Installation Cost			**$29,400**			
Total Capital Cost Differential for ULN Compared to Standard Low NOx Burner			**$134,400**			
				Total Annual Cost		**$27,283**
				NOx Reduction (tons/yr)		**6.57**
				Cost of Control ($/ton - NOx)		**$4,153**