Footprint Power Salem Harbor Development LP

Salem Harbor Redevelopment Project

Prevention of Significant Deterioration Permit

Response to Comments on

Draft Permit Number NE-12-022, Transmittal Number X254064

Introduction

On September 9, 2013, notices were published in the Salem Evening News and the Boston Globe for public review and comment on the Draft Prevention of Significant Deterioration (PSD) Permit for the Footprint Power Salem Harbor Development LP's Salem Harbor Redevelopment (SHR) Project in Salem, Massachusetts. The comment period was extended to November 1, 2013. MassDEP also held a public hearing at the Bentley Elementary School in Salem, MA on Thursday, October 10, 2013. Comments were submitted by various parties during the public comment period.

After careful review of all comments received, MassDEP has made a final decision to issue the PSD Permit. As required by 40 CFR part 124 (Procedures for Decision making), MassDEP has prepared this document, known as the "response to comments" (RTC) that describes and addresses any significant issues raised during the comment period and describes the provisions of the Draft PSD Permit that have been changed and the reasons for the changes. The PSD Fact Sheet has also been changed, to reflect changes that were made to the Draft PSD Permit.

MassDEP's decision making process has benefitted from the various comments and additional information submitted. All changes to the Draft PSD Permit are described in detail below and are contained in the Final PSD Permit. The analyses underlying these changes are explained in the PSD Fact Sheet and the responses to comments that follow.

The Final PSD Permit and RTC are available on MassDEP's website at http://www.mass.gov/eea/agencies/massdep/air/approvals/footprint.html . MassDEP is providing copies (electronic or hard copy) of the Final PSD Permit and RTC to everyone who commented on the Draft Permit or who requested copies of these documents. Copies of the Final PSD Permit also may be obtained by writing or calling MassDEP between the hours of 8:45 AM and 5:00 PM, Monday through Friday, excluding holidays:

Cosmo Buttaro, Environmental Engineer
MassDEP, Northeast Regional Office
205A Lowell Street
Wilmington, MA 01887
Telephone number: (978) 694-3200
Cosmo.Buttaro@ state.ma.us

MassDEP reviewed the significant comments received from commenters and in many cases grouped related comments together. Comments expressing general opposition to, or general support of, the proposed facility have been noted and deemed subsumed into more specific comments, to which MassDEP has responded below.

In some cases, MassDEP has included original comments nearly verbatim for the reader's convenience. In others, MassDEP has included brief summaries of those comments to remind the reader of the topics being discussed. Even though each comment submitted has not been reproduced here in its entirety, and many of the details of each comment were not repeated in the summary comments, please be assured that MassDEP has carefully read and considered every comment in its entirety. The form of this RTC is simply designed to structure MassDEP's responses and make them more accessible to the general public. No significance should be attached to the form in which MassDEP cited or summarized the original comment in this RTC. The complete text of every comment as submitted, and a complete copy of the transcript from the public hearing, is in the administrative record and available by request.

TESTIMONY AND COMMENTS	
NAME & AFFILIATION	**DATE RECEIVED**
1. Ida E. McDonnell, United States Environmental Protection Agency	10/30/13 emailed letter 11/1/13 hard copy letter
2. John Keenan, Massachusetts State Representative	Oral testimony at hearing
3. George W. Atkins, Patricia Maguire Meservey, The Salem Partnership	10/31/13 hard copy letter
4. Jeff Barz-Snell, Salem Resident, Salem Alliance for the Environment (SAFE)	Oral testimony at hearing
5. Jane Bright, HealthLink	Oral testimony at hearing 11/1/13 emailed letter and email comment
6. Jeff Brooks, Salem Resident	Oral testimony at hearing 10/14/13 and 11/1/13 emails, and 10/17/13 letter
7. Paul R. Campbell, Pipe Fitters Local 537	Oral testimony at hearing
8. Shanna Cleveland, Conservation Law Foundation (CLF) and Elizabeth Michaud, Michel Beheshti, Jeff Brooks, Andrea Celestine, William Dearstyne, Linda Haley, Douglas Haley, HealthLink, Clean Water Action, Jane Bright, Martha Dansdill, Rosalind Nadeau, Sue Kirby (350 Massachusetts), Dorian Williams (a Better Future Project-350 Massachusetts), Jody Howard, Marlene Faust	11/1/13 emailed letter

9. Dominic Cucinotti, Salem Resident	10/21/13 email
10. Sonja Cucinotti, Salem Resident	10/18/13 email
11. William E. Dearstyne, Salem Resident	11/1/13 emailed letter
12. Rob DeRosier, Salem Resident, Salem Chamber of Commerce President, Footprint Power Salem Harbor Operations LLC Environmental Health and Safety Manager	Oral testimony at hearing
13. Elise Desmond, Milton Resident	10/5/13 email
14. George Economides, Salem Resident	10/13/13 email
15. Ken Eisenberg, Cambridge Resident	10/24/13 email
16. Meghan Emmers	Oral testimony at hearing
17. Timothy Fandel, Plumbers and Gas Fitters Local 12	Oral testimony at hearing
18. Pat Gozemba, Salem Alliance for the Environment (SAFE)	Oral testimony at hearing Written testimony at hearing
19. Linda Haley, Marblehead Resident	Oral testimony at hearing 11/1/13 emailed letter
20. Susan Kirby, Salem Resident, 350 Massachusetts	Oral testimony at hearing 11/1/13 emailed letter
21. Robert Liani, Jr., Coffee Time Bake Shop, Salem, Salem Chamber of Commerce	Oral testimony at hearing
22. Lauren A. Liss, Rubin and Rudman LLP on behalf of Footprint Power Salem Harbor Development LP	11/1/13 emailed letter 11/4/13 hard copy letter
23. Alison Miller, Salem Resident	11/1/13 emailed letter
24. Lynn Nadeau, HealthLink	Oral testimony at hearing 11/1/13 emailed letter
25. George Pyros, Mitsubishi Power Systems Americas Inc.	10/1/13 emailed letter, 10/7/13 email
26. Nancy Ramsden, Salem Resident	10/21/13 email
27. Sue Reid, Conservation Law Foundation (CLF)	Oral testimony at hearing
28. Wallace and Clare Ritchie, Salem Residents	10/19/13 email
29. Stan Rogowski	10/20/13 email
30. Scott Silverstein, Footprint Power Salem Harbor Development LP	Oral testimony at hearing Presentation Slides received in 10/11/13 e-mail
31. Robert J. Wengronowitz, Boston College Student	10/14/13 email
32. Dorian Williams, Medford Resident, A Better Future Project	Oral testimony at hearing
33. Ed Wolfe, Salem Resident	Oral testimony at hearing
34. Patricia Zaido, The Salem Partnership	Oral testimony at hearing

Changes to the PSD Permit

The following is the list of revisions that MassDEP made from the Draft PSD Permit to the final PSD Permit based upon comments received. The list includes a brief description of the revision, and the location in the RTC document and PSD Fact Sheet where MassDEP provides a more detailed description of the revision.

- The Best Available Control Technology (BACT) analyses for all subject PSD pollutants, for all emission units contained in the Applicant's PSD permit application have been attached to the PSD Fact Sheet as Appendix 1 (pages 42 – 105, below).
- All references to Lowest Achievable Emission Rate (LAER) have been removed from the PSD permit and the PSD Fact Sheet, with exception that the reader is directed to the MassDEP CPA Approval for an explanation of the LAER determination. LAER and Nonattainment review is a state regulated program, administered at 310 CMR 7.00 Appendix A. An explanation of these issues can be found in the MassDEP CPA Approval concurrently issued with the PSD Permit for the SHR Project.
- Since all references to LAER have been removed from the PSD Permit and PSD Fact Sheet, any comparison of LAER to BACT is no longer germane to the PSD Permit or PSD Fact Sheet. However, a comment was received regarding the LAER and BACT emission limits and associated control strategies. As such, this issue is addressed within the BACT and LAER sections of this Response to Comments (RTC) document.
- MassDEP utilized the EPA October 1990 draft New Source Review Workshop Manual and the MassDEP June 2011 BACT guidance document for the evaluation of BACT for this project including the evaluation of energy, environmental and economic impacts of all control options in its selection of BACT for each pollutant. Additional discussion of this issue can be found in the BACT sections of this RTC document and the PSD Fact Sheet.
- MassDEP does not have the electronic capability at this time to provide a "hyperlink" as was suggested, to the Applicant's modeling analysis. MassDEP can provide CD/DVD copies of the modeling analysis for the proposed SHR Project upon request.
- To ensure that the National Ambient Air Quality Standards (NAAQS) and PSD increments are protected in all instances, MassDEP has compiled information on the applicable background concentration levels, the NAAQS and applicable Significant Impact Levels (SILs). This information can be found in the RTC document page 18, Table B. The Applicant provided comment (November 1, 2013) and also provided technical information (December 11, 2013 supplemental application submittal) to MassDEP from the combustion turbine vendor, General Electric (GE), pertaining to emissions of particulate matter (PM) and carbon monoxide (CO). The turbine vendor indicated that PM emissions, project wide, could be reduced by approximately 25 percent from the levels contained in the Draft PSD Permit. Specific PM emission reductions could be obtained at various operating scenarios. (See Attachment 1, Table A-1, highlighted text.) The turbine vendor has also supplied new performance data that show that CO will be controlled to less than 2.0 parts per million by volume, dry basis, corrected to 15% O_2 (ppmvdc) at the minimum emission compliance load and that with greater loads the CO emissions will not exceed 8.0 lbs/hr with and without duct firing.

This emission cap is achievable because the turbines are able to operate more efficiently under higher load conditions. The Applicant also corrected an error in its calculation of CO emissions during start up and shut down. The Applicant incorrectly assumed that if the plant were shut down on Friday night and restarted on Monday morning this would result in a cold start (a startup after a shutdown of more than 72 hours) rather than a warm start (a start up after a shutdown of approximately 60 hours). Since warm starts result in lower CO emissions than cold starts, this correction reduced the plant's annual CO emissions. In addition, in response to public comments, MassDEP required the Applicant to include an oxidation catalyst on its proposed auxiliary boiler (EU3), further reducing facility wide CO emissions. Taken together, these actions have resulted in the reduction of facility-wide CO emissions, to 88 tons per year (tpy), a level that is below the PSD significance level of 100 tpy. This 88 ton per year limit on CO emissions is set forth in the CPA Approval issued concurrently with the PSD Permit and is a federally enforceable limit. As a result, CO emissions are no longer subject to PSD review and the PSD Permit no longer contains limits for CO emissions.

- Pollutants listed in the Draft PSD Permit and Draft PSD Fact Sheet have changed. The Draft PSD Permit and Fact Sheet listed all PSD pollutants and included other non-PSD pollutants. All non-PSD pollutants have been removed from the PSD Permit and PSD Fact Sheet. Furthermore, the reduction in CO emissions to 88 tons per year (tpy), below CO PSD significance level of 100 tpy, eliminated CO from PSD review. In addition, both SO_2 and VOC are proposed to be emitted at less than their PSD Significance levels; thus SO_2 and VOC have also been removed from the PSD Permit. PSD Applicability for the proposed SHR Project is now limited to regulating nitrogen oxides (NO_x), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfuric acid mist (H_2SO_4) and Greenhouse Gases (GHG).
- As mentioned above, the BACT analyses are attached to the PSD Fact Sheet and identified as Appendix 1. Each emission unit's PSD applicable pollutants have been reviewed and evaluated for BACT. MassDEP has reaffirmed its acceptance of BACT for each PSD applicable pollutant for the proposed SHR Project.
- The Draft PSD Fact Sheet erroneously contained the startup and shutdown emission limits of 23 and 29 lbs, per event, respectively, for PM/PM10/PM2.5 which are actually the startup and shutdown emission limits for VOC (see August 6, 2013 supplement to Application, Plan Approval, and PSD Permit). This has been corrected in the PSD Fact Sheet. An error was also found with respect to the BACT emission limits for the auxiliary boiler. The Draft PSD Fact Sheet erroneously contained a BACT H_2SO_4 emission limit of 0.0010 lb/MMBtu instead of 0.0001 lb/MMBtu as stated in the Draft PSD Permit and Proposed Plan Approval (See December 21, 2012 Application, Appendix B and August 20, 2013 supplement to the Application). This has been corrected in the PSD Permit and PSD Fact Sheet.
- With the addition of the oxidation catalyst on the auxiliary boiler (EU3) come collateral impacts on H_2SO_4 emissions. The oxidation catalyst has the potential to convert an additional quantity of SO_2 to $H_2SO_{4.}$ Therefore, there is an increase in the sulfuric acid (H_2SO_4) emission limit for the auxiliary boiler from 0.0001 lb H_2SO_4 pounds per million British thermal units (lb/mmBtu) to 0.0009 lb H_2SO_4/mmBtu. This H_2SO_4 emission limit has been reviewed by MasDEP and determined to be BACT for H_2SO_4 for EU3. This is reflected in the PSD Permit emission limit table and the PSD Fact Sheet related to H_2SO_4 BACT emission limit.

- The $PM/PM_{10}/PM_{2.5}$ BACT emission limit for the combustion turbines has been reduced from 0.0088 lb/mmBtu to 0.0071 lb/mmBtu. The Applicant has provided 25 potential operating scenarios at various seasonal conditions (differing ambient temperature, ambient pressure and ambient humidity) during which the $PM/PM_{10}/PM_{2.5}$ emission rate varies from 0.0038 lb/mmBtu to 0.0071 lb/mmBtu. The Applicant states that at 0 degree Fahrenheit the gas turbines can achieve the $PM/PM_{10}/PM_{2.5}$ rate of 0.0038 lb/mmBtu and at a high temperature of 105 degree Fahrenheit can achieve the $PM/PM_{10}/PM_{2.5}$ of 0.0047 lb/mmBtu. MassDEP has reviewed all of the submitted annual projected operating scenarios for the proposed SHR Project, and all combustion turbine operating conditions (duct burner firing and duct burner not firing) and as stated above, has determined that 0.0071 lb/mmBtu is BACT for $PM/PM_{10}/PM_{2.5}$. This discussion may be found in the PSD Fact sheet, the RTC below and in the PSD Permit emissions Table 2.
- BACT emissions limits for $PM/PM_{10}/PM_{2.5}$ start-ups and shutdowns have increased from the Draft PSD Permit. However, the $PM/PM_{10}/PM_{2.5}$ emissions during start-up and shutdown will never exceed the steady-state, non start-up/shutdown $PM/PM_{10}/PM_{2.5}$ BACT emission limit in pounds per hour. Therefore, the modified $PM/PM_{10}/PM_{2.5}$ start-up/shutdown emission limits are determined to be BACT by MassDEP. The issue is further explained in the PSD Fact Sheet and RTC sections pertaining to start-up/shutdown emissions.
- Specific changes to the Draft PSD Permit are identified below.
  - Section I. Reference to the EPA and MassDEP Delegation Agreement have been removed.
  - Section II. An oxidation catalyst was added to EU3 and is identified as PCD8.
  - Section II. All reference to CO is removed from Table 1.
  - Section III. Table 2. CO emission limits have been removed.
  - Section III. Table 2. $PM/PM_{10}/PM_{2.5}$ emission limits have been reduced.
  - Section III. Table 2. VOC, SO_2, NH_3, smoke and opacity have been removed.
  - Section III. Table 2. Start-up/shutdown $PM/PM_{10}/PM_{2.5}$ emission limits have been increased per event. (However, at no time will these emissions exceed $PM/PM_{10}/PM_{2.5}$ BACT governing steady state combustion turbine operations.)
  - Section III. Table 2. Note 7. CO emissions have been eliminated.
  - Section III. Table 2. Note 11. Additional information has been supplied regarding PVEC CO_2 emission factor verses proposed SHR Project CO_{2e} and CO_2 emission factor.
  - Section III. Table 2. Note 13. Discussion of BACT verses LAER stringency removed.
  - Section III. Tables 2, 3, 4 and 5. All references to VOC, CO, NH_3, smoke and opacity have been removed.

Responses to Comments

<u>Prevention of Significant Deterioration (PSD)</u>

A comment was received pertaining to PSD:

- "…a total of six pollutants emitted from this proposed gas power plant will be classified ….as having a significant emission rate….also classified as a 'major source'...."

Response:

Under the PSD Regulations at 40 CFR 52.21, if the proposed source is one of twenty eight (28) specific source categories listed at 40 CFR 52.21(b)(23), and it has the potential to emit 100 or more tons per year (tpy) of one or more PSD pollutants, the applicant must obtain a PSD Permit. Footprint's emission units fall under one of those 28 listed PSD categories. As such, the project is classified as a major source on the basis of potential nitrogen oxides (NO_x) emissions exceeding 100 tpy and Greenhouse Gas (GHG) emissions exceeding 100,000 tons carbon dioxide equivalent (CO_2e) per year. Therefore, the project must undergo the PSD review process.

Once under PSD review as a major source, the substantive PSD review requirements, including compliance with Best Available Control Technology (BACT), apply to the pollutants emitted at major rates (NO_x and GHG), as well as the other PSD-regulated pollutants which would be emitted at or above their respective significant rates, as follows: PM (25 tpy), PM10 (15 tpy), PM2.5 (10 tpy) and sulfuric acid mist (7 tpy).

<u>Best Available Control Technology (BACT) Analysis</u>

Several comments were received pertaining to the BACT analysis, including:

- "The Fact Sheet's BACT analysis only provided the results of the BACT analysis but not the analysis itself."
- "…EPA recommends the MassDEP attach the applicant's BACT analysis as an appendix to the Fact Sheet or include a hyperlink that links the Fact Sheet to the applicant's BACT analysis."
- "…while Lowest Achievable Emission Rate (LAER) and BACT may result in similar emissions rates for the pollutant under review, LAER and BACT are separate technology standards used in different permitting programs with different policy and regulatory requirements."
- "…a BACT analysis requires the permitting agency to evaluate the energy, environmental and economic impacts for any control option to determine if any significant collateral impact exists that would preclude a control option to be selected as BACT…"
- "the permit and application do not properly conduct BACT analyses…"
- "…PSD Permit establishes CO BACT without conducting the proper BACT analysis…"

- "…permit applications with lower CO and VOC permit limits are under review (2013 Cove Point LNG project)…"
- "…no explanation for VOC emissions increase during duct firing while CO does not increase…"
- "…auxiliary boiler emission limits: 9 ppm NOx, 47 ppm CO, 11.8 ppm VOC; proposed emission limits high, Delegation Agreement not followed for boiler BACT…"
- "…SCR would be BACT for the auxiliary boiler and consistent with MassDEP's 2011 BACT Guideline Document, Delegation Agreement not followed…"
- "…the Delegation Agreement was not followed re: PM BACT…"
- "…the draft/proposed permits establish a BACT limit for greenhouse gas emissions, …, it is unclear whether the project will achieve the same levels of efficiency and the heat rate limits of recently permitted projects…"
- "…the permit references additional greenhouse gas emissions from nitrous oxide and methane, but it does not appear to account for the methane and nitrous oxide emissions in determining compliance with the emission limit for total GHGs…"

Response:

MassDEP has modified the appropriate section of the PSD Fact Sheet by removing reference to LAER, since LAER is a separate technology standard that is not used in the PSD permitting program.

The applicant performed a project-specific top-down BACT analysis in accordance with the BACT analysis procedures cited in the PSD regulations at 40 CFR 52.21 and the "Agreement for Delegation of the Federal Prevention of Significant Deterioration (PSD) Program by the United States Environmental Protection Agency, Region 1 to the Massachusetts Department of Environmental Protection" ("Delegation Agreement") with USEPA Region 1 (signed April 11, 2011).

The applicant's top-down BACT analysis is appended to the final PSD Fact Sheet as Appendix 1. Based on MassDEP review, the analysis conforms to USEPA Guidance and results in BACT determinations and emissions limitations consistent with the Draft PSD Fact Sheet and Draft PSD Permit. The PSD Fact Sheet now refers to MassDEP's review of this analysis as the basis for MassDEP's BACT determinations. Please note that the applicant has obtained emissions guarantees from the turbine manufacturer for carbon monoxide (CO) and particulate matter (PM) emissions that are lower than those contained in the Draft PSD documents. The final PSD Permit and PSD Fact Sheet reflect the revised lower PM values as enforceable BACT emissions limitations. Since each turbine's hourly not-to-exceed CO value has been reduced, and Footprint has been required to install, operate and maintain an oxidation catalyst on the Auxiliary Boiler, allowable CO emissions from the Footprint proposal will now be less than the PSD Significance level of 100 tpy; therefore, CO has been removed from the PSD Permit. In addition, sulfur dioxide (SO2) and volatile organic compounds (VOC) have been removed from the PSD Fact Sheet and PSD Permit since neither criteria pollutant will be emitted at or above its applicable PSD significance level. Finally, since ammonia (NH_3) is not a PSD pollutant, it has also been removed from the PSD Permit. All of these air contaminants are however regulated by the 310 CMR 7.02 Plan Approval which is being issued concurrently with the PSD Permit.

As stated above, MassDEP has added the applicant's BACT analysis to the final PSD Fact Sheet. Please note, however, that MassDEP follows the guidance contained in the October 1990 USEPA draft New Source Review Workshop Manual at page B.8. It states that "…an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document, to the satisfaction of the review agency and for the public record that the control option chosen is, indeed, the top, and review for collateral environmental impacts." The USEPA Guidance goes on to state that "[i]f 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."

BACT for CO and BACT for VOC are outside the scope of this PSD Permit, but are addressed in the state issued 310 CMR 7.02 CPA Approval.

The Cove Point CO and VOC emission limits referenced by commenters are only proposed values, and are not permitted limits. Furthermore, each gas turbine has its own unique emissions profile. The proposed Cove Point project would be subject to lower CO and VOC emissions limits; however, the NOx limit is 25 percent higher than the proposed SHR Project (the Cove Point NOx BACT of 2.5 ppm versus the SHR Project NOx BACT of 2.0 ppm). For the SHR project, this increased NOx emission limit would equate to a potential NOx emissions <u>increase</u> of 36.2 tons per year (tpy)compared to the claimed potential increase of more than 20 tpy CO and 8 tpy VOC. More importantly, NOx emissions from the Footprint proposal must comply with LAER as well as BACT; and MassDEP has determined that NOx LAER is 2.0 ppm, not 2.5 ppm as required for the Cove Point proposal. Furthermore, if Cove Point were required to reduce its NOx BACT from 2.5 to 2.0 ppm—as required by the SHR PSD Permit—it is a likely consequence that the Cove Point CO and VOC emissions would increase. Given the case-by-case nature of the BACT process, MassDEP has chosen to require a stringent NOx emission rate as NOx BACT for the SHR Project at the expense of marginally higher CO and VOC BACT limitations. The Applicant's BACT analysis evaluated the energy, environmental and economic impacts of the interrelated control options for each pollutant. Upon review, MassDEP concluded that the particular combination of emissions limitations contained in the PSD Permit is justified. Please further note that, as a result of comments submitted by the applicant concerning CO emissions from the GE turbines, the hourly, not-to-exceed CO emission limitation for each turbine has been reduced from 11 pounds to 8.0 pounds. This revised limit results in less CO emissions from the SHR project while maintaining the stringent NOx BACT emissions limitation.

VOC emission limits increase during duct firing operation, as opposed to non-duct firing operation, primarily due to the firing of additional fuel and the efficiency of the oxidation catalyst. The applicant has provided data from their equipment vendor GE that VOC emissions increase during duct firing operation because duct firing results in larger increases in the VOC mass emission rate and concentration than in the CO emission rate and concentration. Oxidation catalysts are less efficient for controlling VOC emissions than for CO emissions. Also as noted above, VOC has been removed from the PSD Permit since allowable VOC emissions are below the VOC PSD significance level.

Regarding the auxiliary boiler, a combined cycle gas turbine is not analogous to a standalone boiler with respect to exhaust characteristics, technical feasibility of particular emissions controls, or quantitative emissions concentrations or emissions factors. For example, each has different combustion air demands, which lead to different volumetric flows through each type of machine and therefore different achievable BACT emissions limits on a part per million (ppm) basis. BACT for boilers (the SHR auxiliary boiler) was evaluated in accordance with the Delegation Agreement, guidance contained in the October 1990 USEPA draft New Source Review Workshop Manual and MassDEP's 2011 BACT Guideline Document.

GHG BACT has been addressed in the updated PSD BACT analysis for GHG emissions (Section 4.1.5 of the Applicant's December 11, 2013 submital) and that analysis has been appended to the PSD Fact Sheet. The Footprint design thermal efficiency is 57.9 percent. Concern that this value exceeds the proposed thermal efficiency values cited in a letter written by USEPA's Steven Riva (Chief, Permitting Section, Air Programs Branch) addressing recently approved PSD Permits concerning GHG emission values and thermal efficiencies is misplaced. The use of thermal efficiencies is not a recommended regulatory requirement due to heat rate degradation, duct firing operation/no duct firing operation, ambient temperature, cooling technology, and number of start-ups and shutdowns. Thus the GHG BACT for the SHR Project is expressed in pounds of CO_{2e} per megawatt hour.

Furthermore, the GHG BACT emission limit is expressed as "CO_{2e}" rather than CO_2. CO_{2e} incorporates all federally enforceable GHGs emitted from emission units at the proposed SHR Project the including CO_2, methane and nitrous oxide.

Particulate Matter (PM/PM_{10}/$PM_{2.5}$)

Several comments were received pertaining to Particulate Matter emissions, including:

- "…MassDEP is forcing 1 million people to take on avoidable health risks every year for the next 40 years to cover one to two years of a power shortfall that can be met with existing power plants…"
- "… there is *no* safe level of particulate matter for atmosphere humans will be breathing…"
- "…GE will now guarantee [lower] filterable plus condensable particulate stack emissions for operating loads greater than MECL…this results in a 25% reduction in potential to emit particulate matter..."
- "…distinguish between filterable and condensable limits for PM…"
- "…MassDEP has determined that the Footprint position regarding the PVEC (Pioneer Valley Energy Center) emission limit of 0.004 lb/MMBtu has merit and concludes that the PM emission rate of 0.0088 lb/MMBtu represents BACT for PM/PM10/PM2.5."

Response:

The Footprint ambient air quality impacts study documented that worst case $PM_{2.5}$ emissions from the proposed SHR Project (plus a conservative background value, plus interactive sources located nearby to the proposed SHR Project Site) will comply with the health based $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). Also, please note that Footprint requested a "25 percent lower" $PM_{2.5}$ emission limitation as BACT for $PM_{2.5}$ for its turbines. This lower $PM_{2.5}$ BACT emission limit is contained in the PSD Permit.

All of the $PM/PM_{10}/PM_{2.5}$ emissions limitations contained in the Plan Approval and PSD Permit include filterable and condensable PM. Filterable PM will be measured via USEPA Reference Test Method 201A and condensable PM will be measured by USEPA Reference Test Method 202. As long as the sum total of both PM species is at or below the $PM_{2.5}$ BACT emission limitation, the facility will be in compliance with that standard.

MassDEP has evaluated the PM emission limits and guarantees for the Pioneer Valley Energy Center (PVEC) provided by Mitsubishi Power Systems Americas, Inc. (MPSA) for the M501GAC gas turbine utilizing ultra dry low NOx (DLN) combustors. To date, there is no empirical data available to MassDEP supporting the 0.004 lb/mmBtu emission limit. A review of the recently available GE combustion turbine data indicates that the $PM/PM_{10}/PM_{2.5}$ emission rate at various operating scenarios and ambient temperatures varies from a low of 0.0038 lb/mmBtu to 0.0071 lb/mmBtu. For the reasons more fully set out in the PSD Fact Sheet, MassDEP has lowered the $PM/PM_{10}/PM_{2.5}$ BACT value in the PSD Permit and the Plan Approval to 0.0071 lb/mmBtu based on its GE Energy 107G Series 5 Rapid Response Combined Cycle Plant emission data.

Footprint expects to operate the gas turbines in various operational configurations throughout the calendar year experiencing seasonal fluctuations in ambient temperature, pressures and humidity, all of which have an effect upon gas turbine performance and emissions. To be responsive to the Independent System Operator (ISO) – New England (NE) requirements to generate electricity, the SHR Project.

must be capable of operating at all seasonal conditions and responsive to various electric power demands. As such, GE Energy provided updated performance data for the GE Energy 107F Series 5 Rapid Response CCP. The $PM/PM_{10}/PM_{2.5}$ emissions data across the entire operating range at various seasonal atmospheric conditions will vary from a low of 0.0038 lb/mmBtu to 0.0071 lb/mmBtu. MassDEP believes that the $PM/PM_{10}/PM_{2.5}$ emissions range of 0.0038 to 0.0071 lb/mmBtu represents an accurate PM emissions profile for the gas turbine under the proposed operational scenarios and anticipated seasonal conditions in the Salem area.

Footprint's gas turbine vendor, GE, has indicated that there are operating scenarios where the PM emissions are less than the PVEC PM emission limit of 0.004 lb/mmBtu. However, there are other operating scenarios having PM emissions greater than 0.004 lb/mmBtu. Based upon a review of available $PM/PM_{10}/PM_{2.5}$ emissions data from the EPA's RBLC (RACT/BACT/LAER Clearinghouse), the PVEC PSD permit and application and the emissions data provided by GE Energy, MassDEP has determined that the $PM/PM_{10}/PM_{2.5}$ emission limit of 0.0071 lb/mmBtu represents BACT for PM. This $PM/PM_{10}/PM_{2.5}$ BACT emission limit properly governs these emissions over all proposed SHR project operational scenarios.

Lowest Achievable Emission Rate (LAER)

(Outside the Scope of PSD Permit-Pertains Solely to State CPA Approval)

Two comments were received pertaining to the LAER technology standard, including:

- "…the auxiliary boiler has an ultra low NOx burner on it but it doesn't look like LAER was considered when they were selecting the burners…"
- "…Lowest Achievable Emission Rate (LAER) and BACT may result in similar emissions rates for the pollutant under review, LAER and BACT are separate technology standards used in different permitting programs with different policy and regulatory requirements…"

Response:

MassDEP has supplied ambient ozone monitoring data to USEPA demonstrating that the Commonwealth is attaining the 75 ppb ozone NAAQS. Though having data showing attainment would normally mean that LAER was no longer required in permitting decisions, MassDEP has retained the provisions requiring LAER in our regulations and therefore, SHR is subject to LAER.

The NOx emission limits for the auxiliary boiler and emergency RICE (reciprocating internal combustion engine/generator set and fire pump) represent LAER. There were no more stringent applicable SIP emission limitations, no projects found with lower emissions performance achieved in practice, or lower emissions limits set in permits on the basis of LAER for RICE. The Plan Approval language regarding LAER has been clarified as stated above.

MassDEP has modified the appropriate section of the PSD Fact Sheet by removing any reference to LAER, since LAER is a separate technology standard that is not used in the PSD permitting program. LAER is a technology standard utilized in the new source review permitting program that exclusively reviews non-attainment pollutant permitting of major stationary sources. The non-attainment review program is administered by MassDEP through the plan approval permitting process (pursuant to Regulations 310 CMR 7.02 and 310 CMR 7.00 Appendix A).

Startup/Shutdown Operations (SU/SD)

Several comments were received pertaining to SU/SD operations, including:

- "…starting and stopping of the turbines which leads to significant amounts of emissions to be dispersed into our neighborhoods… until the exhaust heats up to operating temperature and the ammonia starts injecting into the selective catalyst during start-up…"

- "…during startups, the SCR system cannot be turned on until the temperature inside the Heat Recovery Steam Generator (HRSG) at the SCR grid reaches a temperature of approximately 575 deg F… combined-cycle units can often take as long as 180 minutes to reach this temperature…"
- "…the Siemens SGT6-5000F turbine emits up to 24 lb of NO_x over a 12 minute start-up period and 15.44 lb/hr after the MECL is reached and therefore, 36.4 lb/hr of NO_x during an hour that includes a startup…"
- Elevated amounts of emissions during start-up and shutdown of these turbines differ between submittals provided in charts by the Energy Facilities Siting Board (EFSB) dated July 12, 2013 and MassDEP's, Table 3 of the PSD Draft Fact Sheet.
- "…Gas turbine start-up and shutdown NOx emissions, Delegation Agreement not followed re: BACT for start-up and shutdown emissions…"

Response:

Combustion turbine NO_x emission rates during startup are affected by the temperature of the SCR catalyst. In order for the SCR catalyst to be effective in controlling NO_x emissions, it has to reach and maintain a temperature in the range of approximately 550 to 650 Degrees Fahrenheit prior to the introduction of ammonia to control NO_x emissions and to minimize emissions of unreacted ammonia. Prior to this point, called the minimum emissions compliance load (MECL) which is the point when the SCR catalyst temperature and other SCR system parameters are satisfied for SCR operation, NO_x emissions are essentially emitted uncontrolled. Therefore, it is advantageous from an emissions standpoint to have rapid response turbines with quick-start capability like the GE and Siemens turbines that were under consideration for the Footprint project, i.e., turbines that reach the MECL in a minimum amount of time.

MassDEP acknowledges that the GE 7FA turbines proposed for the Footprint project emit up to 93.5 pounds (lb) of NO_x during an hour that includes a startup, given restricted NO_x emissions of no more than 89 lb per startup event over a period not to exceed 45 minutes. However, note that this emission rate is only true for a "cold" startup. The applicant has indicated in their plan submittal that there will be no more than 13 cold startups per year. Startups may be cold, "warm", or "hot" with diminishing emission rates and duration, respectively, before the MECL is reached and the turbine would then be allowed to emit NO_x at no more than 18.1 pounds per hour (lb/hr) for the GE 7FA turbines.

The comment states that the Siemens SGT6-5000F turbine emits up to 24 lb of NO_x over a 12 minute start-up period and 15.44 lb/hr after the MECL is reached and therefore, 36.4 lb/hr of NO_x during an hour that includes a startup. The comment does not state whether this NO_x emission rate for the Siemens turbine is for a cold, warm, or hot startup. Based on MassDEP's review of the information submitted in Footprint's application, the Siemens 5000F turbine cannot achieve the 36.4 lb/hr of NO_x for any startup condition. Expected emission rates and durations for warm and hot turbine startups, and shutdowns, are lower than the emission rate and duration for cold startups. Similarly, the emission rates and durations of a simple cycle turbine startup are not comparable to those of a combined cycle turbine like the GE 7FA turbines proposed for the SHR Project. MassDEP requested that Footprint provide a comparison of the startup emission rates and durations for the GE and Siemens combined cycle turbines, as addressed in the August 6, 2013 supplement to the Footprint Application**.** A comparison of the GE and Siemens NO_x startup and shutdown emission data is provided in Table A below. Only the cold start conditions mean the GE turbine emits higher NO_x. However, if one would evaluate a "full cycle," that being a shutdown and cold startup, the GE turbine is lower emitting for NO_x than the Siemens unit.

TABLE A

Comparison of GE and Siemens NO_x Startup/Shutdown Emissions Data (Pounds of NO_x per Event)			
EVENT	**GE 7FA**	**Siemens 5000F**	**Difference**
Cold Start	89	83	6
Warm Start	54	79	-25
Hot Start	28	58	-30
Shutdown	10	20	-10

Older generations of combined cycle gas turbine power plants could take as long as two to three hours to complete a "cold" startup. However, Footprint has chosen to use the newest generation of GE turbines. GE guarantees that these turbines will meet the following parameters: a cold startup takes no longer than 45 minutes to complete; a "warm" startup takes no longer than 32 minutes to complete; a "hot" startup takes no longer than 18 minutes to complete; and a shutdown takes no longer than 27 minutes to complete. The shorter startup and shutdown periods reduce emissions substantially.

The conservative ambient air quality impact analysis protocol required under the state and federal air quality permitting processes must include consideration of worst case air pollutant emissions during turbine startup and shutdown periods. Footprint demonstrated, via use of computer dispersion models which have been approved by USEPA, that combustion turbine startup and shutdown emissions would not result in an exceedance of any applicable, health based NAAQS.

MassDEP environmental engineers reviewed the original Footprint Power plan application and the several supplemental submittals which were made to MassDEP in detail, including information related to the SHR Project's turbines regarding startups, shutdowns and associated emissions. MassDEP based the PSD Fact Sheet and PSD Permit SU/SD numbers on our review of all of the data which was submitted to MassDEP. MassDEP received data from the applicant on August 6, 2013 comparing the difference between GE and Siemens turbines for SU/SD operations. Additional SU/SD emissions data was submitted by the Applicant on January 10, 2014. All of this SU/SD data was more recent than the data provided to EFSB.

Stack Height

Several comments were received pertaining to the stack height, including:

- "…they lowered the stack height from the initial plans from 250 feet to 230 feet to save money."
- "…the proposed stacks will be 230 feet high, much lower than the current stack heights or even the best practices recommendation of over 300 feet…"
- "…the stack would be 20 feet lower then specs called for, which would also impact area residents, particularly the children at the Bentley School…"

Response:

The federal PSD regulations at 40 CFR 52.21 and the Massachusetts Plan Approval Regulations at 310 CMR 7.02 require that any applicant must, among several other things, demonstrate that the worst case air emissions from their proposed emission unit(s) would result in compliance with all applicable, health based, National Ambient Air Quality Standards (NAAQS). This ambient air quality analysis requires the use of computer dispersion models which have been reviewed and approved by USEPA. The inputs to these models include the use of: facility parameters such as stack height, stack velocity, stack temperature, etc., representative background concentrations of each NAAQS attainment pollutant as measured by the Massachusetts ambient air monitoring network, representative meteorological parameters, and the actual emissions of certain large emitters of those pollutants which are located in the area proximate to the proposed facility's location. Footprint originally anticipated constructing a 250 foot stack for the proposed SHR project. However, Footprint's interactive, ambient air quality impact analysis demonstrated that its worst case emissions from the 230 foot stack, plus representative background concentrations, plus emissions from certain nearby large emitters of these pollutants, demonstrates compliance with all applicable, health based NAAQS. Footprint asserted in their Energy Facilities Siting Board (EFSB) filings that they would prefer a 230 foot stack since it would represent an appropriate balance between air emissions impacts and visual impacts.

Air Quality Dispersion Modeling and Ambient Monitoring

Several comments were received pertaining to the air quality dispersion modeling analyses and ambient monitors, including:

- "…the air monitoring station (Lynn, MA.), that is being used as a model is not adequate in representing the air quality for the area where the gas plant is to be built in Salem…"

- "…propose that MassDEP set up a sampling station, prior to issuing an air permit, in our Salem neighborhood that both abut the power plant and the South Essex Wastewater Treatment plant…"
- The Footprint modeling "…[did] not take into consideration anything regarding wind shift…"
- "…very concerned that the proposed project will cause undo harm to those of us living within the plume radius of such a gas plant…"
- "The June 2013 Second Supplement from Tetra Tech shows in Table 6-11 that the predicted maximum 1 hr concentration for NO_2 is 188 µg/m^3: *exactly* equal to the NAAQS for NO_2. This value is higher than that of the September 9, 2013 PPA which shows a predicted value of 166 µg/m$^{3.}$"
- "…there appears to have been a significant change to the analysis with respect to NO2. In one of the earlier scenarios, the cumulative impact of the facility along with the interactive sources appears to reach the 1-hour NAAQS for NO2, 188 µg/m3. See June 2013 revision with modeling for cumulative impacts at Table 6-11 shows that NO2 reaches 188 which is the NAAQS for NO2. They also appear to have changed the tons [of NO_x] per year from 150 to 148.8. However, the final Table 2 of the Proposed Plan Approval shows a maximum impact of 166 ug/m3."
- "…the predicted ambient concentrations are so close to the NAAQS forces a scrutiny of the modeling assumptions made…"
- "…reference to using an urban or rural designation relates to an outdated methodology used in the predecessor model to AERMOD, ISCST…"
- "…disallow the conclusion presented by Footprint for the NO2 1 hour NAAQS based on the misuse of EPA interpretations…"
- "… The interaction source impacts dominate the maximum total concentrations, so the results were reviewed to confirm that the proposed SHR facility does not significantly contribute to any modeled concentration at or above 105.7 ug/m3. This evaluation uses the EPA default 80% conversion of NOx to $NO_{2...}$"
- "…the cumulative impacts (maximum 1-hour plus ambient background) for NO2 and SO2 are well below the 1 hour health-protective NAAQS as well as other short-term exposure guideline levels…"
- "…there are two small areas of isolated peak NO2 one-hour concentrations (in the range of 36 to 42 µg/m3 and well below the NAAQS of 188 µg/m3). 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…"
- "…the dispersion model used rural coefficients…"
- "…there was a release model for ammonia, and it looks like it uses the exact same model to show the dispersion of the accidental release. And it seems a little weird to me to use the same model…"
- "…the Draft PSD Fact Sheet only provided the results from the modeling analysis but not the analysis itself…"
- "The use of Significant Impact Levels (SILs) alone as a screening tool to show compliance with the National Ambient Air Quality Standards (NAAQS) and PSD increments may not be adequate."

- "…why preconstruction monitoring as provided for through the PSD regulations was not undertaken, why the monitors from Lynn and Harrison Avenue were considered appropriate for estimating the impacts of this facility…"
- "…the modeling analysis is defective due to its use of Logan Airport meteorological data. The specific geographic, wind, and other feature differences as between Logan airport and the site that render it inappropriate for use in the modeling…"
- "The PPA states that a 3km radius surrounding the facility was used to determine dispersion coefficients for use in AERMOD and states that rural coefficients were used. In fact, EPA requires that the surface conditions (roughness length, albedo and Bowen Ratio) within a 1 km radius of the anemometer used for dispersion analyses (in this case, Logan Airport), be used as the basis for determining the roughness length used in the model algorithms. The reference to using an urban or rural designation relates to an outdated methodology used in the predecessor model to AERMOD, ISCST."

Response:

MassDEP's response to comments concerning air quality dispersion modeling and ambient monitoring are presented in three sections below:

A. Responses concerning Ambient Background Concentrations/Monitors/Monitoring

Given its location on the southeast perimeter of the Lynn Woods Reservation, the immediate surroundings of the Lynn air monitoring station are somewhat more rural than the immediate surroundings of the SHR Project Site. However, the Lynn station measures regional air pollution being transported to it from highly populated and industrialized areas located upwind within and beyond Lynn, in a sector from the south to southwest of the station. This sector is the same as the predominant prevailing winds in the area that would transport pollution into the Lynn area. From a local perspective, as described in the PSD Fact Sheet, the data from the Lynn monitoring site is considered to be conservative (i.e., has the potential to measure higher pollution concentrations) because Lynn is a more industrialized and densely populated area than the proposed project site area, particularly without the influence of the existing Salem Harbor Station. Furthermore, the SHR Project Site is located adjacent to Salem Harbor, a large water body where potential sources of air pollution are more limited. Therefore, MassDEP required the applicant to use ambient monitoring data from the Lynn station for the most recently available three calendar years 2010, 2011 and 2012.

Concerning the locations of the GE and Wheelabrator Plants with respect to the Lynn monitoring station, these plants are south-southwest of the Lynn monitor. This location places the plants within the south to southwest wind sector that would transport their emissions toward the Lynn monitor. In addition, the GE and Wheelabrator plant emissions were included in the modeling analysis, which means they have been explicitly accounted for over the distribution of possible meteorological conditions. Also, the emissions from existing Salem Harbor Station for calendar years 2010 and 2011 impacted the Lynn monitor when north and northeast winds prevailed during those time periods.

The South Essex Sewerage facility, located adjacent to the proposed SHR Project site, houses several small boilers, emergency generators, water heaters, etc. Total air emissions from the South Essex facility are less than 10 tons per year (tpy). Actual PM_{10}/$PM_{2.5}$ emissions for calendar year 2012 were 0.14 tpy, sulfur dioxide (SO_2) emissions were 0.29 tpy, nitrogen oxides (NO_x) emissions were 3.3 tpy, and carbon monoxide (CO) emissions were 2.7 tpy. The South Essex Sewerage facility is a minor source and has an insignificant contribution to the overall impacts on ambient air quality concentrations in Salem.

MassDEP has compiled Table B (below) listing background ambient concentrations, the applicable NAAQS, background minus NAAQS, and the applicable SIL. The table is presented to address concerns that the initial modeling to determine impact significance/insignificance, and therefore compliance with NAAQS/PSD Increments in the case of insignificant impact findings, might not be adequate.

TABLE B

Difference Between NAAQS and Background Concentrations in Comparison to Applicable SIL

Pollutant	Averaging Time	National Ambient Air Quality Standards (NAAQS)	Background Concentration	Significant Impact Level	Difference Between Background and NAAQS
$PM_{2.5}$	24-hr	35	18.9	1.2	16.1
	Annual	12	7.2	0.3	4.8
PM_{10}	24-hr	150	41	5	109
NO_2	1-hr	188	82.3	7.5	105.7
	Annual	100	19.3	1	80.7

Note: All concentrations are in micrograms per cubic meter.

In all cases, the difference between the NAAQS and background ambient concentration levels is greater than the applicable SIL value. As such, EPA guidance notes that it would be sufficient in most cases for permitting authorities to conclude that sources with impacts below the SIL values will not cause or contribute to a violation of the NAAQS, and additional cumulative modeling is not needed. MassDEP has taken the above approach, i.e. determined that there is no need for additional modeling, in this case.

As described above, ambient monitoring data from MassDEP's Lynn monitoring site for the three (3) year period of 2010 through 2012 were used to characterize background levels of criteria pollutant ambient air concentrations. PSD regulations allow proposed sources to use existing monitoring data in lieu of PSD preconstruction monitoring requirements for a pollutant if the source can demonstrate that its modeled ambient air impact is less than a de minimis amount (also called a significant monitoring concentration or SMC) as specified in those regulations. As shown in Table C below, dispersion modeling conducted by the Permittee predicted maximum proposed SHR Project impact concentrations well below corresponding SMC levels for all pollutants for which SMCs exist.

TABLE C

Preconstruction Monitoring Analysis			
Pollutant	**Averaging Period**	**Significant Monitoring Concentrations (SMC) (ug/m^3)**	**Maximum Predicted Facility Impact (ug/m^3)**
NO_2	Annual	14	0.4
SO_2	24-Hour	13	0.7
PM_{10}	24-Hour	10	4.3
CO	8-Hour	575	112.4

Table C Key:
ug/m^3 = micrograms per cubic meter

EPA had also established an SMC for $PM_{2.5}$ but this SMC was remanded by the United States Court of Appeals for the DC Circuit on January 22, 2013 (No. 10-1413, Sierra Club v. EPA). On March 4, 2013, the EPA Office of Air Quality Planning and Standards issued guidance to applicants and regulators with regard to the ramifications of the January 22, 2013 Appeals Court decision. The pertinent excerpt of this recent EPA guidance is as follows:

> "As a result of the Court's decision, Federal PSD Permits issued henceforth by either the EPA or a delegated state permitting authority pursuant to 40 CFR 52.21 should not rely on the $PM_{2.5}$ SMC to allow applicants to avoid compiling air quality monitoring data for $PM_{2.5}$. Accordingly, all applicants requesting a federal PSD Permit, including those having already applied for but have not yet received the permit, should submit ambient $PM_{2.5}$ monitoring data in accordance with the Clean Air Act requirements whenever either direct $PM_{2.5}$ or any $PM_{2.5}$ precursor is emitted in a significant amount. In lieu of applicants setting out $PM_{2.5}$ monitors to collect ambient data, applicants may submit $PM_{2.5}$ ambient data collected from existing monitoring networks when the permitting Authority deems such data to be representative of the air quality in the area of concern for the year preceding receipt of the application. We believe that applicants will generally be able to rely on existing representative monitoring data to satisfy the monitoring data requirement."

The Lynn monitoring site, located approximately 5.9 miles to the southwest of the proposed SHR Project, is representative of the proposed SHR Project site due to its proximity. Use of the data from this monitoring site is conservative for the following reasons:

a) Lynn is a more industrialized and densely populated area than the proposed SHR Project site, particularly without the influence of the existing Salem Harbor Station after its shutdown and prior to the proposed SHR Project commencing operation. The proposed 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 located closer to the metropolitan Boston area than the proposed SHR Project site. Any potentially elevated ambient background pollutant concentrations from mobile and stationary emission sources located in and around the Boston metropolitan area that may be transported to the proposed SHR Project site via predominant winds from the south or southwest, typically pass the Lynn monitoring location and are therefore represented in the measurement data collected at the Lynn monitoring site.

b) The General Electric Lynn and Wheelabrator Saugus facilities, which have been identified by MassDEP as the only two major industrial emission sources to be modeled cumulatively with the proposed SHR Project emissions for 24-Hour $PM_{2.5}$, are located slightly less than 2 miles from the Lynn monitoring site but are located about 7 miles from the proposed SHR Project site. Therefore, the cumulative modeling compliance demonstration, which includes the background ambient concentrations and impacts from the interactive existing major sources likely double counts the contribution of these sources and therefore, provides additional conservatism to the required modeling results by potentially overestimating cumulative impact concentrations. This is particularly significant given that these two major sources are located to the south-southwest of the monitoring site, which means that they could potentially influence the monitoring site concentrations during winds coming from the south or southwest, the predominant wind directions in this area.

For the reasons set forth above, in accordance with the PSD regulations and recent EPA guidance, MassDEP has determined that preconstruction monitoring is not required.

B. <u>Responses concerning Meteorological/Surface Characteristics/Land Use Model Inputs</u>

The required air dispersion modeling analysis performed by Footprint regarding the SHR Project is central to the overall air quality impact assessment performed for the Project. The modeling work was thoroughly reviewed by MassDEP and found to be compliant with our Modeling Guidance for Significant Stationary Sources of Air Pollution, as well as with EPA modeling requirements for PSD Permit applications. The modeling addressed the impacts of pollutants required under MassDEP and USEPA regulations and had the proper inputs to provide results within the accuracy limits of the model. One input to the model is a 5 year meteorological data set. The meteorological data used in the SHR Project analysis consisted of data collected over the 5 year period from 2006 to 2010. The data set included surface-based measurements and upper air measurements as required by the USEPA-approved meteorological preprocessor (AERMET) to develop a suitable data input file for the USEPA-approved computer dispersion model (AERMOD). The surface data was collected at the Logan Airport station in Boston, which is the closest first order National Weather Station (NWS) to the SHR project, while the corresponding upper air data was collected at the Gray, Maine NWS station. These locations are considered representative of the project area and use of data from these locations is consistent with MassDEP and USEPA guidelines. Once processed via AERMET, the meteorological data included in the input files consisted of wind speed, wind direction, and ambient temperature as well as other directly measured and derived variables. The data in these files are an hour-by-hour representation of the meteorological conditions in the SHR Project area for the entire 5 year period and reflect the hour by hour changes in conditions including varying wind directions (i.e., “wind shift”). Use of the developed meteorological data input files as required to run the AERMOD model means that wind shift was in fact taken into account.

Regarding dispersion coefficients based on AERSURFACE parameters, certain inputs are mandatory to properly execute the AERMOD model. These include the rural/urban designation as well as the calculation of surface roughness length, Bowen Ratio, and albedo. The comment is correct that surface roughness length, Bowen Ratio, and albedo are calculated by the application of the utility program AERSURFACE to the area centered on the location of the meteorological data collection station (i.e., where the anemometer is located). In particular, surface roughness length is determined based on land use out to a radius of 1 km from this location. Bowen ratio and albedo are determined based on land use and other AERSURFACE inputs over a 10 km by 10 km area centered on this location.

The 3 kilometer (km) radius and 1 km radius references are for two different types of inputs to AERMOD. The urban versus rural designation is used to employ the correct dispersion coefficients in the model; and it is a current methodology. The urban or rural designation is required to properly execute AERMOD, just as it was for the predecessor model ISCST, and is an option that is used directly in the model (in this case AERMOD). The designation of urban or rural is based on land use within a radius of 3 km from the proposed new facility being analyzed.

The 1 km radius refers to land use in the area around the location of the meteorological data collection station (in this case at Logan Airport) and is used to determine the surface roughness length, as correctly mentioned in the comment. However, this is an input used in the utility program AERSURFACE, which is a program that allows for the objective determination of surface roughness, bowen ratio, and albedo in the area of the meteorological station. The output data generated by AERSURFACE is used as input to the meteorological preprocessor AERMET. Bowen ratio and albedo are objectively determined by AERSURFACE based on land use classifications over a 10 by 10 kilometer area centered on the meteorological station, as well as other inputs related to moisture conditions and precipitation types and amounts.

Due to the effects that urban areas have on meteorological conditions especially at night (e.g., the urban heat island effect), the land area within 3 km of a proposed project must be assessed using the Auer method in order to classify it as an urban or rural land use designation. This designation is mandatory to correctly run the proper dispersion model and obtain accurate, useable results. In the Auer method, certain land use classifications are associated with the urban designation, and all the others default to rural. Bodies of water are considered to be rural. Using the Auer method, the designation for the entire SHR Project area is based on whether the 3 km area is 50% or more urban. If it is, the urban option is selected in the model and urban dispersion coefficients are used in the modeling. Otherwise, the rural dispersion option is selected. Based upon the Auer method and the actual land use in the area within 3 km of the proposed SHR Project, rural dispersion was properly selected for use in the modeling.

C. Responses concerning Modeling Process and Results

The Application included a conservative predictive analysis of the maximum ambient concentrations of criteria pollutants (i.e., pollutants regulated by a health based National

Ambient Air Quality Standard or NAAQS) and air toxics (pollutants regulated by MassDEP's Air Toxics Guidelines), which are used to evaluate potential human health risks from exposures to chemicals in ambient air that might result when the SHR Project operates. The analysis shows, and MassDEP concurs, that worst case emissions from the SHR Project will not violate any of the applicable NAAQS or MassDEP's air toxics long-term Allowable Ambient Limits (AALs) for carcinogens or short-term Threshold Effects Exposure Limits (TELs) air toxics guidelines for non-carcinogens.

The 188 ug/m^3 impact value incorrectly reported in the June 2013 Second Supplement was based on the most conservative approach that assumes 100% conversion of NO_x to NO_2 in the ambient air (the Footnote for Table 6-11 in the June Supplement incorrectly stated that an 80% conversion rate was used). A 100% conversion assumption is overly conservative and not realistic. The 166 ug/m^3 NO_2 concentration in the Proposed PSD Permit is the predicted impact shown by the dispersion modeling analysis and relied on for the demonstration of compliance with the 1-hour NO_2 NAAQS. 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". When considering how the 166 ug/m^3 impact was derived (project impacts plus interactive source impacts plus ambient air background concentration), the value of 105.7 ug/m^3 has no meaning. It is associated only with the incorrectly reported 188 ug/m^3 impact.

MassDEP properly accepted the conclusion presented by Footprint for the 1-hour NO_2 compliance demonstration since the modeling was correctly performed in accordance with EPA policies and guidance.

The change in the final cumulative impact of the proposed facility for 1-hour NO_2 is not related to the slight change in the expected potential to emit. The basis for the revision is explained above in detail.

The nature of modeling as part of an air quality impact assessment for regulatory compliance is such that many assumptions and elements of the overall analysis lead to results that are overly conservative. Another way of saying this is that due to the conservatism of the analysis, the margin of compliance with the NAAQS will actually be greater than shown because the real world impacts will be lower. One example of the conservatism applied in the analysis is the assumption used for the conversion of NO_x to NO_2 as previously described. Another element of conservatism, also previously described, is the inclusion of GE Lynn and Wheelabrator Saugus as interactive sources in the modeling while also using background ambient air concentrations from the Lynn ambient monitor, which itself is impacted by emissions from these two facilities. Furthermore, additional interactive sources were included in the modeling assuming that they operate continuously at their maximum allowed emission rates when in reality they only operate for a fraction of the total hours in a year.

One comment also mentions the possibility that increased emissions from the SHR Project or from any of the interactive sources (or increased emissions from newly constructed nearby sources) could result in a situation where the NAAQS are violated. The way the proposed SHR Project will be allowed to operate and the way the interactive sources are currently allowed to operate under their existing operating permits is already fully reflected in the impact assessment by virtue of modeling the maximum allowable emission rates. If any of these facilities adds a new emission source or modifies an existing source that results in an increase of emissions then there are MassDEP and USEPA regulations in place to address this. This might include additional project modeling to show that any new emissions do not have significant impacts on existing air quality or cumulative modeling to demonstrate compliance with the NAAQS. The regulations in place and the modeling requirements associated with them are there to ensure that NAAQS violations do not occur, while at the same time allowing facilities the flexibility to make necessary operating and business decisions as long as they comply with all applicable Air Pollution Control Regulations.

When the term "significantly contribute" is used in assessing model-predicted impacts of NO_2, it refers to whether or not the SHR Project is contributing over or under the Significant Impact Level (SIL) of 7.5 ug/m^3. Only the total impacts from the SHR Project plus interactive sources that contain a contribution of 7.5 ug/m^3 or more from the SHR Project need to be considered when evaluating whether the SHR Project will cause or contribute to a NAAQS violation.

Notably, the test for "significance" can often come into play twice in an air quality impact assessment for a pollutant such as NO_2 that has a 1-hour NAAQS. The first test of significance is always employed as it is used to define the significant impact area (SIA) of a proposed new facility on a pollutant by pollutant basis. The SIL for 1-hour NO_2 is 7.5 ug/m^3 and it is assessed based on the maximum impact at each individual receptor in the modeled receptor grid. If the impact is 7.5 ug/m^3 or greater, that receptor then becomes part of the SIA. Once the SIA is defined, that area is subject to a cumulative modeling analysis that includes appropriate interacting sources and background air quality data. In order to receive a permit or plan approval, a proposed project's air impacts must be documented to be in compliance with the appropriate NAAQS. This second phase of modeling is assessed against the NAAQS using the form of the standard, which for 1-hour NO_2 is based on model-predicted daily maximum impacts at the 98th percentile value for each receptor (in the model this represents the 8th high value as opposed to the maximum value).

The second test of significance comes into play when the total impacts are dominated by the interacting sources rather than those of the proposed facility. So the second test of significance is not always used. In this case it was used, because the existing interacting sources dominated the overall impacts. Given that, the results from the cumulative modeling analysis must be reviewed to determine whether the proposed SHR Project is contributing to the cumulative impacts at a level equal to or higher than the NO_2 SIL (7.5 ug/m^3). If determined to be above the SIL cumulative impacts are assessed against the 1-hour NO_2 NAAQS. For this modeling analysis, with the assumption of an 80% conversion rate, this amounted to a single receptor where the total impact was 166 ug/m^3. The SHR Project's contribution to this cumulative impact is 7.8 ug/m^3.

The description of the model-predicted 1-hour NO_2 concentrations with respect to impacts in Environmental Justice or EJ areas and health effects, as contained in the PSD Fact Sheet and as reproduced in one of the comments MassDEP received, is factually based. The modeling was performed in accordance with all applicable MassDEP and USEPA guidelines for this type of air quality impact assessment.

With respect to the accidental release of ammonia, the ammonia emission rate was appropriately determined via the Areal Locations of Hazardous Atmospheres (ALOHA) accidental release model. The comment is referring to the AERMOD model. AERMOD was also used to assess the dispersion of ammonia in the air in the unlikely event that there is an accidental release. The maximum amount of ammonia that could be released into the air (as opposed to the amount staying in the diked area within the enclosure) is the emission rate used in AERMOD.
MassDEP has made available copies of the complete cumulative dispersion modeling analysis in electronic format (CD/DVD) as part of the public record, they may be obtained by request; this has been noted within the PSD Fact Sheet.

Non-Attainment Review – 310 CMR 7.00 Appendix A- Offsets

(Outside the Scope of PSD Permit-Pertains Solely to State CPA Approval)

Two comments were received pertaining to the NOx emissions offsets, including:

- “Allowing Footprint Power to use these credits to produce electricity does not mitigate the fact that they will be emitting tons of toxic emissions from their exhaust stacks on a local level into our neighborhoods.”
- “…Footprint is purchasing credits from Rhode Island for a plant already slated for shutdown… it is illustrative of the problems Footprint faces to comply with disease-causing emissions and does not address local exposure to ozone and resulting illnesses ozone causes to our community…”

Response:

The use of emission offsets for a proposal such as Footprint’s is a legal and regulatory requirement. Instead of being allowed to net out of the requirements for emission offsets, Footprint is using emissions offsets for its worst case NOx emissions, at a 1.26 to 1.0 emission offset ratio, as required by Regulation 310 CMR 7.00-Appendix A. Use of emission offsets at the above ratio is required so that the affected airshed experiences a net air quality benefit.

Greenhouse Gas (GHG) and Global Warming Solutions Act (GWSA)

(Outside the Scope of PSD Permit Pertains Solely to State CPA Approval)

Numerous comments were received pertaining to Greenhouse Gas (GHG) emissions and the Global Warming Solutions Act (GWSA), including:

- CO2 is a pollutant because of its role in anthropogenic global warming. CO2 is known to have considerable negative effects as we increase its atmospheric concentration (as well as in oceans).
- Proposed plant will emit 2.5 million TPY of CO2 and will be a "major contributor" in violating the GWSA.
- Proposed plant is "essentially against the law"….will "generate more pollutants than allowed by a state law mandate"….will run for 40 to 60 years.
- Allowing construction of the plant with its CO2 and methane emissions "cannot be justified with the goals and hopes of the GWSA"
- Concern re: guarantees that the plant will meet the conditions of the GWSA.
- There is no evidence in the record to support MassDEP's proposed Section 61 Findings that this project is consistent with the GWSA. Only analysis MassDEP appears to rely on is the CRA analysis, which covered only through 2025 and was riddled with flawed assumptions. No indication that Footprint presented any information on GHG impacts through 2050.
- MassDEP has a special obligation under GWSA because of requirement to promulgate regulations establishing declining annual aggregate emission limits for sources/categories of sources by January 1, 2012, to go into effect by January 1. 2013 through December 31, 2020. G.L. c. 21N, § 3d; St. 2008, c. 298, § 16. MassDEP's failure to promulgate regulations does not excuse sources of categories from being required to meet mandates of GWSA.
- Footprint is not thinking about the 2050 deadline and has not provided adequate information depicted in any way to comply with emission reduction targets that we need in 2050.
- Constructing a $900 million natural gas plant keeps funding and focus away from investment in green energy technologies … much of the $900 million "will be contributed by the ratepayers" … use the $900 million to build renewable energy sources such as windmills on the Cape.
- Given the climate change trajectory which we are on, building a new natural gas plant is "insignificant and insufficient" to meet the crisis we face. We must invest in conservation, efficiency and alternates such as solar and wind.
- Proposed plant should be compared with conservation and energy reduction.
- Request to see studies review by EFSB that indicates that the proposed plan will reduce the grid's reliance on higher emitting fossil plants, thereby reducing regional CO2 by 450,000 TPY, the equivalent of 103,000 cars.
- Massachusetts is a leader in the U.S. on reducing GHG, but being the best in the U.S. does not relieve us of our responsibility globally.
- It is time for Massachusetts to finally take a pledge of "no new fossil-fired electric generation".

- Concern that too large a percentage of New England grid is powered by natural gas units.
- Science is telling us that 40 years down the road, effects of global warming may include agricultural drought, rising tides, etc.; "burden" will be placed on younger generation. Consider your children when deciding whether to issue air permits that allow more GHG to be put into the atmosphere.
- I support the proposed project because of the national and international emergency of climate change. Based on what we have seen, newer generation fast start combined cycle gas turbine plants like this are really singularly the most important transitional technology we have in the next thirty years, forty years, to get us where we need to go in terms of reducing our carbon emission and decarbonizing our grid.
- Proposed plant will allow us to scale up renewables.
- Will take 25 years to build national high voltage DC infrastructure required to transmit renewable energy all over the US, and to really scale up renewable energy sources.
- If we only have the older generation natural gas plants running, that is worse, given the climate emergency.

Response:

MassDEP notes the many comments and concerns that have been submitted during the public hearing and public comment process regarding GHG emissions from the proposed plant and compliance with the GWSA. MassDEP agrees that global warming and climate change impacts are serious concerns and is dedicated to fulfilling all its obligations under the GWSA.

Since 2008, Massachusetts has been a national leader with respect to global warming and climate change.[1] In December, 2010, then Secretary of Executive Office of Energy and Environmental Affairs (EEA) Ian Bowles established a legally binding statewide GHG emission limit of 25 (%) percent below statewide 1990 GHG emission levels by 2020. In the Determination of Greenhouse Gas Emission Limit for 2020, issued on December 28, 2010, Secretary Bowles' 2020 Determination outlined a portfolio of policies designed to achieve the 2020 statewide emission limit. Since the adoption of the 2020 emission limit, the EEA and its agencies have implemented numerous policies to ensure that the 25% reduction is reached.

MassDEP encourages interested persons to follow the Commonwealth's progress under the GWSA by following the GHG Dashboard which can be found at http://www.mass.gov/eea/air-water-climate-change/climate-change/massachusetts-global-warming-solutions-act/global-warming-solutions-act-dashboard.html. Among other information, this site provides periodic updates on the state's progress under the GWSA, including progress toward meeting the 2020 goals, GHG trends and related information. In addition, EEA recently released the five year progress report on the GWSA which can be found at http://www.mass.gov/eea/docs/eea/gwsa/ma-gwsa-5yr-progress-report-1-6-14.pdf

[1] In 2008, Governor Deval Patrick signed the GWSA into law, making Massachusetts one of the first states in the nation to move forward with a comprehensive program to address climate change. In addition, several other clean energy laws were enacted in Massachusetts in 2008, including the Green Communities Act, Oceans Management Act, Clean Energy Biofuels Act and the Green Jobs Act.

Pursuant to Section 7 of the GWSA and G.L. c. 30, § 61, the proposed project has been reviewed extensively and comprehensively with respect to GHG emissions and GWSA compliance by the Massachusetts Environmental Policy Act (MEPA) unit of EEA, the Energy Facilities Siting Board (EFSB), and MassDEP. The MEPA environmental review process and the EFSB proceedings have resulted in determinations and findings that the proposed project's GHG emissions are in compliance with applicable state laws and requirements, including the GWSA.

MassDEP agrees that when issuing permits, licenses or other approvals for projects that require an Environmental Impact Report (EIR), MassDEP is required to consider reasonably foreseeable climate change impacts, including GHG emissions, and effects such as predicted sea level rise. G.L. c. 30, § 61. In this case, MassDEP considered the reasonably foreseeable climate change impacts of the proposed facility by actively participating in the MEPA environmental review process. See MassDEP Comments on the Environmental Notification Form dated August 28, 2012, MassDEP Comments on the Draft Environmental Impact Report (DEIR) dated January 28, 2013, and MassDEP Comments on the Final Environmental Impact Report (FEIR) dated May 13, 2013. In these comments, MassDEP pointed out the need for the SHR Project Proponent to ensure that there will be additional on-site and off-site mitigation as the remainder of the site is developed. To ensure that this need is addressed, MassDEP recommended that the Secretary require that the Notices of Project Change (NPCs) for such future development of the site include an analysis of the impacts of GHG emissions. MassDEP also recommended that the SHR Project Proponent include mobile sources in its greenhouse gas analysis. The FEIR, the MEPA Certificate on the FEIR, the Public Benefits Determination, and the SHR Project Proponent's Proposed Section 61 Findings reflect, among other things, MassDEP's comments.

On June 10, 2013, the SHR Project Proponent revised its Proposed Section 61 Findings and submitted them to the Secretary as required by the Secretary's Certificate on the FEIR. MassDEP incorporated the SHR Project Proponent's Revised Section 61 Findings in its Proposed Plan Approval.

To respond to the public comments on the SHR Project's GHG emissions and compliance with the GWSA, MassDEP carefully examined the detailed applications for a Plan Approval and a PSD Permit, the ENF, the DEIR, the FEIR, the MassDEP comments and the Secretary's Decision on the SHR Project Proponent's MEPA filings, the SHR Project Proponent's Revised Section 61 Findings incorporated in the Proposed Plan Approval, and the EFSB Decision in the Approval to Construct Proceeding EFSB 12-2. As a result of this review, MassDEP has incorporated all the GHG mitigation measures needed to ensure compliance with the GWSA as determined by the Secretary and the EFSB in the Section 61 Findings in the Plan Approval. MassDEP concludes that the SHR Project as authorized by the Plan Approval including the GHG mitigation measures set forth in the Modified Section 61 Findings is consistent with the GHG reduction targets established by the GWSA.

Secretary Richard K. Sullivan, Jr. issued several documents that summarize and reflect the extensive GHG-related review that took place during the MEPA Environmental Review and the Public Benefits Determination Process including: the August 28, 2012 Certificate on the ENF, the January 26, 2018 Certificate on the DEIR, the May 17, 2013 FEIR Certificate and the June 17, 2013 Public Benefits Determination. The Secretary discussed the GHG analysis in the

FEIR Certificate (at pages 10-13) and stated that the SHR Project Proponent's GHG analysis is consistent with Massachusetts GHG Policy. In addition, required mitigation measures to address GHG emissions are summarized in the FEIR Certificate (at pages 21-22). The FEIR Certificate also required the SHR Project Proponent to submit a revised summary of GHG emissions (referred to as Table 3-1). On June 10, 2013, the SHR Project Proponent submitted the revised Table 3-1 as required.

Subsequently, consistent with the provisions of An Act Relative to Licensing Requirements for Certain Tidelands, Secretary Sullivan issued the Public Benefits Determination, finding that the proposed SHR Project will have a public benefit. Among other considerations, the Secretary considered environmental protection and preservation, specifically determining that the proposed SHR Project has been designed to avoid, minimize and mitigate associated impacts including the impacts of GHG emissions by inter alia its choice of fuel and technology, installation of a solar photovoltaic (PV) array, and incorporation of energy efficiency measures into the design of the Administration and Operation Buildings.

The Public Benefits Determination (at pages 6-7) sets forth a summary of the measures that the SHR Project Proponent will implement to avoid, minimize and mitigate GHG emission impacts. These measures include compliance with the Regional Greenhouse Gas Initiative (RGGI). To comply with RGGI, the SHR Project Proponent is required to obtain and retire one CO2 allowance for each ton of CO2 the SHR Project emits. Massachusetts auctions nearly 100% of the RGGI allowances and is required to invest at least 80% of those auction proceeds in energy efficiency measures in the Commonwealth. These energy efficiency measures will yield GHG emission reductions. The Public Benefits Determination estimates that the SHR Project Proponent would be required to pay $4,000,000 per year for the necessary allowances.[2]

The Public Benefits Determination states that in addition to obtaining the RGGI allowances, the SHR Project Proponent will implement the following measures to mitigate the impact of its GHG emissions:

- Use of combined cycle natural gas turbines;
- Solar PV array with potential to offset 175 tons per year of GHG emissions;
- Measures designed to ensure that 56.5 tons of GHG reductions will be achieved each year, or 29%, from Administrative Building and Operations Building:
    - Administrative Building is designed to meet the United States Green Building Council's Leadership in Energy and Environmental Design (LEED) Certification at the Platinum level and includes a green roof, geothermal heat pumps for heating and cooling, variable volume ventilation fans, increased insulation to minimize heat loss, lighting motion sensors, climate control and building energy management systems, a 10% reduction for lighting power density (LPD) (and identifies the

[2] This amount may underestimate the yearly cost of such allowances. It is estimated that the Proponent will have to obtain 2,000,000 allowances per year. The current cost of each allowance is approximately $3.00. At a cost of $3.00 per allowance, the Proponent will have to pay approximately $6,000,000 per year for the required allowances. The cost of allowances is projected to increase in response to the promulgation of new regulations which reduce the cap on greenhouse emissions. See 310 CMR 7.70.

potential for larger reductions), and water conserving fixtures that exceed building code requirements; and

- Operations Building includes a high albedo roof, geothermal heat pumps for heating and cooling; increased insulation to minimize heat loss, daylighting, lighting motion sensors; climate control, building energy management systems, a 10% reduction for LPD (and identifies the potential for larger reductions), and water conserving fixtures; and

- Submission to the MEPA Office of a Certification by the SHR Project Proponent indicating that all of the measures proposed to mitigate GHG emissions or measures to achieve equivalent GHG reductions have been implemented.

Some comments suggest that Massachusetts should take a pledge of "no new fossil-fired electric generation." MassDEP acknowledges those comments, but notes that such comments are beyond the scope of the Department's review in this matter. MassDEP further notes that the GWSA does not prohibit the construction of new fossil fuel facilities. Indeed, M.G.L. c. 21N, § 9 expressly provides; "Nothing in this chapter shall preclude, prohibit or restrict the construction of a new facility or the expansion of an existing facility if all applicable requirements are met and the facility is in compliance with regulations adopted pursuant to this chapter." Consistent with this provision, the Massachusetts Clean Energy and Climate Plan for 2020 (CECP) assumes that the existing coal burning facility in Salem would be shut down and the energy previously generated by Salem would come from natural gas fired plants located somewhere in Massachusetts.[3]

The Secretary's FEIR Certificate determined that the proposed SHR Project is consistent with the CECP for 2020 and the GWSA. In the FEIR Certificate, the Secretary specifically noted that the CECP for 2020 expressly relies on RGGI and the replacement of the energy generated by the existing coal burning plants in Salem and Somerset with energy generated by natural gas fired plants to help meet the state's goal of reducing GHG emissions by 25% by 2020. The Secretary pointed out that DEIR included an analysis that showed that by displacing energy generation by dirtier plants, the SHR Project would reduce regional GHG emissions by 457,626 tons per year (tpy)[4].

Like the Secretary, the EFSB concluded that the proposed SHR Project would lead to an overall reduction of GHG emissions by displacing less efficient sources. The EFSB recognized that the CECP for 2020 envisioned the possibility that the existing coal burning plant in Salem could be replaced by a natural gas fired plant and that natural gas could be a bridge to a clean energy future. Thus, the EFSB determined that construction of the proposed SHR Project is consistent with the 2020 goal.

---

[3] The 2020 Climate Plan further assumed that this change in energy production would reduce CO2 emissions by 872,262 metric tons per year.

[4] In the DEIR, the Proponent stated that the proposed facility would reduce CO2 emissions by 457,626 tons per year. This number is based on a study done by Charles River Associates provided as Appendix C of the DEIR. In its comments on the DEIR, the Department of Energy Resources questioned this number. In the Final Decision in the Approval to Construct Proceeding, EFSB 12-2, the EFSB concluded that that the proposed facility would result in a net reduction of regional GHG emissions, but acknowledged that the exact amount of the reduction is uncertain.

The EFSB further noted that the CECP for 2020 includes two scenarios for achieving the goal of reducing GHG emissions by 80% by 2050. Scenario One is based primarily on eliminating the use of fossil fuels. Scenario Two is based on maximizing efficiency and conservation. The EFSB noted that Scenario Two represents a plausible scenario in which the proposed SHR Project could operate into the future without preventing the Commonwealth from meeting the 2050 goal.

The EFSB also recognized that additional measures may be required to ensure that the Commonwealth meets the 2050 goal. Accordingly, the EFSB put the SHR Project Proponent on notice that it would have to comply with evolving regulations to meet the GWSA targets. The EFSB stated its commitment to ensure that evolving GHG policies and regulations are addressed fully.

Some comments point to, or appear to rely on, a specific section of the GWSA (G.L. c. 21N, § 3d; St. 2008, c. 298, § 16) to oppose the issuance of a Final Plan Approval or PSD Permit for the proposed SHR Project. In pertinent part, the GWSA provides at c. 21N, § 3(d):

> The department shall promulgate regulations establishing a <u>desired level</u> of declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions (emphasis added).

In the context of reviewing whether the proposed SHR Project meets applicable state and federal requirements that govern issuance of a Plan Approval and issuance of a PSD Permit, the commenters' reliance on § 3(d) is misplaced. In any event, MasDEP has fully complied with section 3(d). Among other things, on December 9, 2013, MassDEP has issued final regulations that impose a new regional cap on carbon dioxide emissions from fossil fuel fired electric generation. See 310 CMR 7.70. Under these regulations, emissions of CO_2 will be limited to 91 million tons in 2014. The annual cap will be reduced 2.5% per year from 2015 through 2020. This will result in an annual regional cap of 78 million tons in 2020. These regulations, and similar regulations and statutes in the other eight RGGI states, will ensure that emissions from power plants in 2020 are approximately **half** of their 2005 totals. These declining annual aggregate limits ensure that power plants will comply with the reduction goals in the CECP for 2020, and that reductions within the electric generating sector are much steeper than the overall 25% reduction called for in the CECP for 2020.

Non-Attainment Review – 310 CMR 7.00 Appendix A

Public Benefits and Alternatives Review

(Outside the Scope of PSD Permit, Pertains Solely to State CPA Approval)

Several comments were received pertaining to Public Benefits and Alternatives Review, including:

- "…Footprint repeatedly and erroneously attempts to compare the added emissions [from] this new plant to a plant that will have been closed for two years. Correctly compared to the baseline of zero emissions, the added pollutants and greenhouse gases are a threat to the community…"
- "…Removing the old plant facility, remediating the property and reusing the site such that tax revenues and jobs are replaced has total support… there is considerable local disagreement that the way to meet those **economic** goals is to burden Salem and the region **environmentally** with a new fossil fuel plant…"
- "Given the high volatility of natural gas prices, occasional restricted availability in winter months, the warnings in the study that financing, costs of demolition and remediation alter the economic viability of such a power plant, the touted economic benefits of tax revenues and jobs must be disallowed as reasons to support this proposal."
- "The site offers the Permittee the opportunity to significantly reduce air, water supply, wastewater, noise, visual, and other impacts **relative to the existing** Salem Harbor Station facility… Footprint falsely presents this proposed plant as a replacement for the coal plant…"
- "The proposed Facility also serves the Commonwealth's interest in developing renewable energy sources. That is, the quick-start technology designed into the proposed Facility facilitates and supports the development of wind generation…no wind development under proposal is dependent on this plant being built…"
- "Footprint makes no attempt to measure the cost burden for citizens to deal with the health costs from exposure to PM2.5 and ozone."
- "…Footprint has made no plans to develop the rest of the site, an economic drain on the city."
- There will not be an increase in jobs associated with the Footprint project, but rather a decrease local long term employment opportunities. Gas plants employ far fewer employees than office buildings and other industrial uses for the same amount of land needed for the Footprint project.
- MassDEP accepted the CRA analysis of the potential greenhouse gas emissions impacts of the facility without examining the underlying assumptions… MassDEP should have conducted a more thorough analysis of the claims and studies provided by the project proponent…"

Response:

MassDEP has treated the Footprint proposal as a new facility. With regard to emissions of NOx, Footprint will fully comply with all applicable Nonattainment New Source Review requirements including the requirement to obtain offsets at a 1.26 to 1.0 offset ratio and Lowest Achievable Emission Rate. MassDEP has not allowed Footprint to obtain credit for any reductions in emissions that result from the shutdown of the existing coal burning power plant in 2014. As set forth in the CPA Approval, MassDEP determined that Footprint adequately demonstrated that the "benefits of the proposed source significantly outweigh the environmental and social costs…"

Footprint's demonstration that the benefits of the proposed Facility outweigh its costs is supported by the determinations made by the Secretary of EEA and the EFSB with regard to the SHR Project. On May 17, 2013, Secretary Sullivan, pursuant to the MEPA (G.L.c.30, ss.61-62I) and Section 11.08 of the MEPA regulations (301 CMR 11.00), issued the Certificate for the FEIR No. 14937 for the SHR Project. In addition, on June 17, 2013, Secretary Sullivan issued a Public Benefits Determination concluding that the SHR Project will have a positive public benefit. Furthermore, EFSB issued a Decision on October 10, 2013 for the SHR Project approving the petition of Footprint Power Salem Harbor Development LP to construct a 630 MW natural gas-fired, quick-start, combined-cycle facility at the present location of the Salem Harbor Station in Salem, Massachusetts. For the reasons set forth in the foregoing documents, the SHR Project adequately demonstrates that the "benefits of the proposed source significantly outweigh the environmental and social costs."

Health Impacts

Several comments were received pertaining to Health Impacts, including:

- "…studies often fail to be reflective of the real risks of pollutants and particulate matter..."
- "…do not believe the models offered to date provide a true picture of the risks the proposed 690MW gas burning plant poses for our community…"
- "…[Footprint] claims improvements **compared to the existing plant**..."
- Several other collateral health impacts comments may be found in sections addressing startup/shutdown operations, stack height, modeling, offsets, public benefit/alternatives review, particulate matter, BACT and LAER.

Response:

The federal PSD regulations at 40 CFR 52.21 and the Massachusetts Plan Approval Regulations at 310 CMR 7.02 require that any applicant must, among several other things, demonstrate that the worst case air emissions from their proposed emission unit(s) would result in compliance with all applicable, health based, attainment National Ambient Air Quality Standards(NAAQS). This ambient air quality analysis requires the use of computer dispersion models which have been reviewed and approved by USEPA. The inputs to these models include the use of: representative background concentrations of each NAAQS attainment pollutant as measured by the Massachusetts ambient air monitoring network, representative meteorological parameters, and the actual emissions of certain, large emitters of those pollutants which are located in the area proximate to the proposed facility's location, and the worst case air emissions from the SHR

Project. Footprint's interactive, ambient air quality impact analysis demonstrated that its worst case emissions, plus representative background concentrations, plus emissions from certain nearby large emitters of these pollutants, would result in compliance with all applicable, health based NAAQS.

With respect to possible harm to public and environmental health and welfare, the application included a conservative predictive analysis of the maximum ambient concentrations of criteria pollutants (i.e., pollutants regulated by a National Ambient Air Quality Standard or NAAQS) and air toxics (pollutants regulated by MassDEP's Air Toxics Guidelines) that might result when the project operates. The analysis shows, and MassDEP concurs, that worst case emissions from the SHR Project will not violate any of the applicable NAAQS or MassDEP's air toxics long-term Allowable Ambient Limits (AALs) for carcinogens or short-term Threshold Effects Exposure Limits (TELs) air toxics guidelines for non-carcinogens. (Please see pages 15-17 of 60 inclusive of the Footprint CPA Approval.)

<u>Environmental Justice (EJ) Evaluation</u>

Several comments were received pertaining to Environmental Justice, including:

- Based on the statement from Footprint, "The dispersion modeling completed for the SHR Project demonstrates that the predicted maximum impacts from the Facility 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….. 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*."*
- "…there is no safe level of PM2.5 and they themselves point out exceedances of PM2.5, it is clear there are health impacts."
- Based on the statement from Footprint, "The Proposed SHR Facility is not located in or adjacent to an EJ area, and Footprint has demonstrated that there will be no disproportional impact to any such community. Indeed, the proposed facility will be an improvement over emissions from the existing facility, and will reduce regional emissions of NOx, SO2 and CO2 to the benefit of all area residents. Footprint has demonstrated that emissions from the proposed SHR facility itself will be well within the NAAQS, which are designed to be health-protective of the most sensitive populations."
- "..the proposed facility is adjacent to an EJ community…"
- "…compare the increased emissions to a plant that will have been closed for two years such that the baseline for comparison should be zero emissions…""At 188 NAAQS with the proposed facility contributing 22.2% of the total 188, they are hardly "well within" NAAQS."

Response:

The 166 ug/m^3 NO_2 concentration in the Proposed Plan Approval is the actual predicted impact shown by the dispersion modeling analysis and relied on for the demonstration of compliance with the 1-hour NO_2 NAAQS. It reflects a modeling methodology whereby NO_2 is assumed to be formed by an 80% conversion of the Project stack emissions of oxides of nitrogen (NO_x). In reality, the conversion of NOx to NO_2 in the atmosphere is something that changes hour by hour and is significantly controlled by the amount of ozone available in the air to allow the conversion to occur. The actual conversion rate can be higher or lower than 80% and is often lower, so assuming a constant conversion of 80% for all hours in an analysis yields a conservative result. The 188 ug/m^3 impact value reported in the June 2013 Second Supplement was based on the most conservative approach that assumes 100% conversion of NO_x to NO_2 in the ambient air. (The Footnote for Table 6-11 incorrectly stated that an 80% conversion rate was used). This assumption is overly conservative and does not reflect the actual atmospheric chemistry that occurs. Therefore, the original result was not an accurate reflection of what the analysis revealed when the more realistic level of conservatism was applied.

The nature of modeling as part of an air quality impact assessment for regulatory compliance is such that many assumptions and elements of the overall analysis lead to results that are overly conservative. Another way of saying this is that due to the conservatism of the analysis, the margin of compliance with the NAAQS will actually be greater than shown because the real world impacts will be lower. One example of the conservatism applied in the analysis is the assumption used for the conversion of NO_x to NO_2 as previously described. Another element of conservatism, also previously described, is the inclusion of GE Lynn and Wheelabrator Saugus as interactive sources in the modeling while also using background ambient air concentrations from the Lynn ambient monitor, which itself is impacted by emissions from these two facilities. Furthermore, additional interactive sources were included in the modeling assuming that they operate continuously at their maximum allowed emission rates when in reality they only operate for a fraction of the total hours in a year.

The comment also mentions the possibility that increased emissions from the SHR Project or from any of the interactive sources (or increased emissions from newly constructed nearby sources) could result in a situation where the NAAQS are violated. The way the proposed SHR Project will be allowed to operate and the way the interactive sources are currently allowed to operate under their existing operating permits is already fully reflected in the impact assessment by virtue of modeling the maximum allowable emission rates. If any of these facilities adds a new emission source or modifies an existing source that results in an increase of emissions then there are MassDEP and USEPA regulations in place to address this. This might include additional project modeling to show that any new emissions do not have significant impacts on existing air quality or cumulative modeling to demonstrate compliance with the NAAQS. The regulations in place and the modeling requirements associated with them exist to ensure that NAAQS violations do not occur, while at the same time allowing facilities the flexibility to make necessary operating and business decisions as long as they comply with all applicable Air Pollution Control Regulations.

Furthermore, MassDEP has treated the Footprint proposal as a new facility, which it is. MassDEP has not allowed Footprint to claim credit for any emission reductions that may result from the shutdown of the existing coal burning plant in 2014. With regard to the emissions of NOx from the SHR Project, Footprint must provide emission offsets, at a 1.26 to 1.0 offset ratio, and keep its emissions at or below the Lowest Achievable Emission Rate as required by 310

CMR 7.00-Appendix A. Indeed, Footprint must fully comply with all applicable Nonattainment New Source Review requirements. As a result, Footprint has, demonstrated to the satisfaction of MassDEP that the "benefits of the proposed source significantly outweigh the environmental and social costs."

Footprint properly modeled the impacts of the facility and determined that the emissions of the facility would not contribute to a violation of the NAAQS or PSD increments. (See RTC section Air Quality Dispersion Modeling and Ambient Monitoring Subsection C). As set forth in the PSD Fact Sheet, the modeling demonstrates that the SHR Project's emissions of PM2.5 and NO2 will not have disproportionately high human health or environmental effects on EJ areas. As set forth in the PSD Fact Sheet, EJ populations may benefit from the reductions in regional GHG emissions that will result from the SHR Project. As set forth in the CPA Approval, Footprint has demonstrated to the satisfaction of MassDEP that the benefits of the SHR Project outweigh its social and environmental costs.

Natural Gas (NG)

Several comments were received pertaining to Natural Gas, including:

- "Will the price of natural gas change the procedural protocol on how this plant will operate?"
- "[bringing natural gas into Salem Harbor] would open up Salem Harbor to cruise ships; a gas line would go under Fort Street - (a residential area) also that the pipe line is smaller than the amount of gas that needs to go through it…"
- "[natural gas extraction via fracking technology]… addressing the threat of well-water and groundwater contamination posed by fracking-related injections…"
- "…when I think of ships containing LNG coming into the busy harbor, I get so frightened…"
- "A gas line would go under the residential area of Fort Street I understand, and the pipe line is smaller than the amount of gas that needs to go through it."
- "There is no natural gas capacity currently at that site."
- "Will a pipeline need to be drilled under residential neighborhoods?"
- "Will LNG tankers need to deliver fuel through the harbor? Is Salem being targeted to become an LNG port?"
- "With health and environmental risks associated with extracting natural gas via fracking, we are clearly not ready for this plant!"
- "We do not have enough supply of natural gas."

Response:

The analysis of Footprint's application, which resulted in issuance of the Proposed Plan Approval and Draft PSD Permit, was based upon combustion of natural gas only in the two combined cycle gas turbines. Both documents contain enforceable conditions requiring that solely natural gas be combusted in those turbines. Any change to the approved fuel of use would require an entirely new filing, a new analysis, and if merited, the issuance of significant modifications to the Plan Approval and PSD Permit.

The issues related to hydro-fracking, LNG storage and transport, and any natural gas supply or pricing or delivery issues, are beyond the scope of MassDEP's review of the applications for the Footprint PSD permit and CPA approval applications.

Use of Urea verses Ammonia

Two comments were received pertaining to the use of urea verses ammonia, including:

- "…tried several times to bring up the facts about using urea as opposed to aqueous ammonia for emissions controls… tried to explain the dangers of using, transporting and storing aqueous ammonia…"
- "…there is an alternative to ammonia by using a harmless urea solution…"

Response:

Neither the federal PSD Regulations nor the MA Plan Approval Regulations require MassDEP to dictate the reagent to be used, in conjunction with Selective Catalytic Reduction, to control NOx emissions from a proposed power plant. MassDEP is charged with ensuring that those emissions will comply with Best Available Control Technology and Lowest Achievable Emission Rate as applicable. MassDEP required Footprint to analyze the effects of a worst case ammonia (NH3) spill involving the entire contents of the proposed NH3 storage tank. The details of this analysis can be found on pages 20-22 of 60 inclusive of the Footprint CPA Approval, section entitled "Accidental Release Modeling of Aqueous Ammonia (NH3)". Furthermore, Footprint is subject to federal risk management planning and accidental release prevention requirements for any on-site quantities of flammable and extremely hazardous chemicals listed under 40 CFR 82, and under the General Duty Clause of the federal Clean Air Act, Section 112(r).

MassDEP has established health based ambient air guidelines for a variety of chemicals (air toxics). These air guidelines establish two maximum impact limits for each chemical listed: an Allowable Ambient Level (AAL), which is based on an annual average concentration; and a Threshold Effects Exposure Limit (TEL), which is based on a 24-hour time period. In general, AALs are lower than TELs, and represent the concentration associated with a one in one million excess lifetime cancer risk, assuming a lifetime of continuous exposure to that concentration. For chemicals that do not pose cancer risks, the AAL is equal to the TEL. AALs and TELs are expressed in micrograms per cubic meter (ug/m3). MassDEP required Footprint to demonstrate that the worst case NH3 stack emissions from its proposal would not exceed MassDEP's air toxics guidelines for NH3. Using the same USEPA reviewed and approved computer dispersion models employed during the NAAQS analysis, Footprint's worst case NH3 emissions were predicted to be: 0.034497 ug/m3 on an annual basis, versus an AAL of 100 ug/m3; and a worst case 24 hour NH3 concentration of 1.093673 ug/m3 versus a TEL of 100 ug/m3.

Appeal Procedures and Venue

Two comments were received pertaining to the appeal procedures, including:

- A citizen requested to be informed regarding their rights to appeal the decision of the Footprint air permit.
- "The Draft Prevention of Significant Deterioration Fact Sheet (the "Fact Sheet") misstates the law regarding appeals of air permits…. MassDEP needs to clarify the venue and procedure for appeals of its final PSD Permit Decision in a manner which conforms to its codified enabling authority."

Response:

The final Plan Approval (for State Issued Permits and Approvals ONLY) includes the following information regarding the applicable Appeal Process.

> APPEAL PROCESS
>
> This Plan Approval is an action of MassDEP. If you are aggrieved by this action, you may request an adjudicatory hearing. A request for a hearing must be made in writing and postmarked within twenty-one (21) days of the date of issuance of this Plan Approval.
>
> Under 310 CMR 1.01(6)(b), the request must state clearly and concisely the facts, which are the grounds for the request, and the relief sought. Additionally, the request must state why the Plan Approval is not consistent with applicable laws and regulations.
>
> The hearing request along with a valid check payable to the Commonwealth of Massachusetts in the amount of one hundred dollars ($100.00) must be mailed to:
>
> Commonwealth of Massachusetts
Department of Environmental Protection
P.O. Box 4062
Boston, MA 02211
>
> This request will be dismissed if the filing fee is not paid, unless the appellant is exempt or granted a waiver as described below. The filing fee is not required if the appellant is a city or town (or municipal agency), county, or district of the Commonwealth of Massachusetts, or a municipal housing authority.
>
> MassDEP may waive the adjudicatory hearing-filing fee for a person who shows that paying the fee will create an undue financial hardship. A person seeking a waiver must file, together with the hearing request as provided above, an affidavit setting forth the facts believed to support the claim of undue financial hardship.

The PSD Permit is subject to requirements of the Delegation Agreement with US EPA, Region 1 to implement and enforce the federal Prevention of Significant Deterioration (PSD) regulations as found in 40 CFR 52.21, the Code of Federal Regulations (CFR), 7-1-10 Edition, with amendments.

The provisions in 40 CFR 124.19 will apply to all appeals to the EPA Environmental Appeals Board (EAB) on PSD permits issued by MassDEP under the April 4, 2011 Delegation Agreement, except with respect to permit conditions that do not derive from federal PSD requirements, for which applicable Massachusetts administrative procedures apply. If a PSD permit issued by MassDEP is appealed to the EAB, MassDEP has the primary responsibility for defending the permit before the EAB and the discretion to withdraw the permit under 40 CFR 124.19(d).

MassDEP will notify the applicant and each person who has submitted **written** comments or requested notice of the final permit decision of their right to appeal, and this notice is required to state that for federal PSD purposes and in accordance with 40 CFR 124.15 and 124.19:

- 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 EAB to review any condition of the permit decision.
- The effective date of the permit is 30 days after sevice 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.
- If an appeal is made to the EAB, the effective date of the permit is suspended until the appeal is resolved.

A petition for review shall include a statement of the reasons supporting that review including documentation that any issues being raised were raised during the public comment period (including any public hearing) to the extent required by the PSD Program regulations, and when appropriate a showing that the condition in question is based on (i) a finding of fact or conclusion of law which is clearly erroneous or (ii) an exercise of discretion or an important policy consideration which the EAB should review.

Procedures for appealing permits can be found at 40 CFR 124. More information on the appeals process and the EAB can be found at http;//www.epa.gov/eab. The EAB Practice Manual can be found at http://www.epa.gov./eab/pmanual.pdf. The EAB website and the Practice Manual should be carefully reviewed prior to filing an appeal.

Monitoring, Record Keeping, and Reporting

Several comments were received pertaining to monitoring, record keeping and reporting, including:

- "Require PM CEMS instead of parametric monitoring for PM,"

- "Limit of 0.5 grains/100 scf sulfur content in natural gas, but no particular method to ensure continuous monitoring, reporting and compliance."
- "…recommend requiring that those monthly records be submitted to MassDEP on a quarterly basis in addition to the semi-annual reporting requirement…"

Response:

Mt. Tom Station, a coal fired power plant, is required to install and operate PM CEMS as part of a settlement agreement and not as a Plan Approval or Permit requirement; final technical details concerning the operation of this PM CEMS have been resolved and the PM CEMS has just recently become operational. Brayton Point, also a coal fired power plant, employs parametric PM monitoring, not a PM CEMS. Palmer Renewable Energy (PRE) was originally proposed as a construction and demolition (C&D) waste fired power plant. The PM CEMS was originally required due to the proposed combustion of C&D waste and to also be used as a surrogate for the heavy metals emissions that would have occurred as a result of combusting C&D waste. The PRE proposal has subsequently been changed to combust clean biomass and is currently in litigation concerning local zoning issues. The PRE facility has not yet been built, and therefore a PM CEMS has not been installed nor operated. As opposed to the coal fired Mt. Tom power plant and the proposed, but not yet built PRE biomass fired power plant listed above, the proposed SHR Project is a natural gas only, combined cycle turbine, power generating facility. The actual filterable and condensable, in-stack PM concentrations that a PM CEMS installed on a natural gas turbine would measure is thus extremely small; and significantly smaller than the in-stack PM-fine concentration that would be emitted by either a coal fired or biomass fired emission unit. Natural gas fired combustion turbines with low PM emission concentrations provide a challenging emissions monitoring environment. These exhaust streams are extremely high volume, low concentration gas streams. MassDEP is of the opinion that the current PM CEMS on the market have not demonstrated an ability to adequately measure PM over the long term that enable them to be used in Massachusetts as a direct compliance monitor, particularly on a natural gas fired only combustion turbine. Therefore, MassDEP did not require PM CEMS for the proposed SHR Project. In addition, both the proposed PVEC and Brockton combined cycle combustion turbine projects are not required to install PM CEMS.

With respect to sulfur content of fuel, Footprint Power is required by federal regulations to comply with the monitoring requirements concerning the sulfur content of natural gas as contained in 40 CFR 60 Subpart KKKK.

As the owner/operator of a major source of certain criteria air pollutants the SHR Project owner/operator shall be required to submit semi-annual and annual compliance reports pursuant to 310 CMR 7.00-Appendix C. In addition, any facility which is required to install, operate and maintain continuous emissions monitoring systems (CEMS). Footprint must employ NOx, CO and ammonia CEMS, and an O_2 CEMS as a reference gas. Footprint is also required to submit quarterly CEMS excess emissions reports to MassDEP.

Noise

(State Only Requirement – Not PSD Subject)

One comment was received pertaining to noise:

- "How noisy would plant operation be for nearby neighbors? These gas burning units can be as loud as jet engines. How will that impact our neighborhoods?"

Response:

The proposed SHR project is required to comply with the MassDEP noise guidance and ensure the facility is not having an impact of greater than 10 dbA over existing ambient conditions. In addition, Footprint was required to evaluate and incorporate best sound migration controls and/or strategies to all sound producing activities associated with the proposed project. Please see Section C-NOISE (State-Only Requirement) pages 47-51 of 60 inclusive of Plan Approval, Application No. NE-12-022, which addresses all noise-related issues. The SHR project is projected to increase sound by not more than 6 decibels above ambient background (where background does not include operation of the existing coal and oil fired Salem facility.)

Article 97,

97th Amendment to the Massachusetts Constitution

(State Only Requirement – Not PSD Subject)

Two comments were received pertaining to Article 97, including:

- "…the 97th Amendment to the State Constitution. The amendment reads: The people shall have the right to clean air and water, freedom from excessive and unnecessary noise, and the natural, scenic, historic, and esthetic qualities of their environment."
- "The people shall have the right to clean air and water, freedom from excessive and unnecessary noise, and the natural, scenic, historic, and esthetic qualities of their environment; and the protection of the people in their right to the conservation, development and utilization of the agricultural, mineral, forest, water, air and other natural resources is hereby declared to be a public purpose. The general court shall have the power to enact legislation necessary or expedient to protect such rights."

Response:

The [Massachusetts] Department of Environmental Protection is the state agency responsible for ensuring clean air and water, the safe management of toxics and hazards, the recycling of solid and hazardous wastes, the timely cleanup of hazardous waste sites and spills, and the preservation of wetlands and coastal resources. (This is MassDEP's Mission Statement).

To ensure a clean environment for the citizens of Massachusetts, MassDEP utilizes its regulatory authority to review permit applications and issue approvals/permits that comply with state and federal regulations/laws that protect and preserve the public health and welfare of the citizens of the Commonwealth.

Opposition to the Proposed Footprint SHR Project

Several comments were received that pertain to opposition for the Proposed Footprint SHR project, including:

- Approximately 22 parties/commenters provided comments and/or testimony in opposition of the Proposed Footprint SHR Project.

Response:

MassDEP duly notes the opposition to the Footprint SHR project.

Support and Conditional Support for the Proposed Footprint SHR Project

Several comments were received pertaining to support and conditional support of the Proposed Footprint SHR Project, including:

- Approximately 8 parties/commenters provided comments and/or testimony in support and/or conditional support of the Footprint SHR project.

Response:

MassDEP duly notes the support and conditional support for the Footprint SHR project.

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.

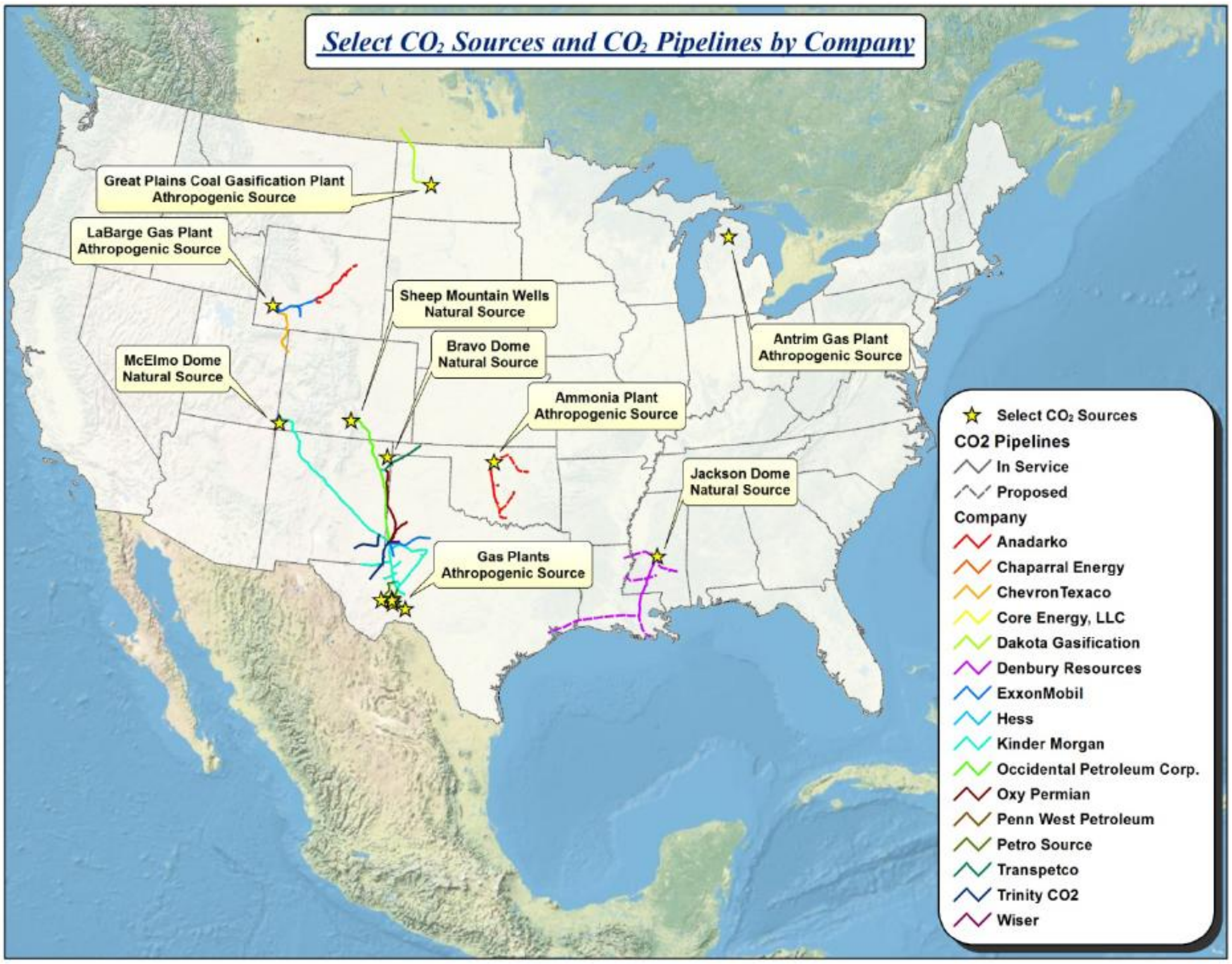
Step 4: Evaluation of Energy Efficiency and Heat Rate

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 $\leq$ 2890 MMBtu/hr/unit DF $\leq$ 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)	
a.	DPF Capital Cost Estimate (per Milton Cat)		$90,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$4,500
Total Equipment Cost (TEC)			**$94,500**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$7,560
b.	Erection and Handling	(TEC*0.14)	$13,230
c.	Electrical	(TEC*0.04)	$3,780
d.	Piping	(TEC*0.02)	$1,890
e.	Insulation	(TEC*0.01)	$945
f.	Painting	(TEC*0.01)	$945
Total Direct Installation Cost			**$28,350**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$9,450
b.	Construction/Field Expenses	(TEC*0.05)	$4,725
c.	Construction Fee	(TEC*0.1)	$9,450
d.	Start up	(TEC*0.02)	$1,890
e.	Performance Test	(TEC*0.01)	$945
Total Indirect Installation Cost			**$26,460**
Total Capital Cost (TCC)			**$149,310**

Capital Recovery		**$24,338**
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 generator 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)	$1,493
c.	Insurance: (TCC*0.01)	$1,493
d.	Administration: (TCC*0.02)	$2,986
Total Indirect Operating Cost		**$6,260**
Total Annual Cost		**$31,318**
PM Reduction (tons/yr)		**0.05**
Cost of Control ($/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						Normal Load Cases Emissions for Each Season	
	Assumed Operating Profile Normal Loads					starts/wk			starts/yr			CO			VOC				
	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%	Baseline Emissions at 30 ppmvdc corrected to 3% O2 (tpy)	9.46
Economic Factors from MassDEP Form BWP-AQ-BACT		SCR Emissions at 3 ppmvdc corrected to 3% O2 (tpy)	0.95
Capital Recovery Factor (CRF)	0.163		

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)	
a.	Capital Cost Estimate (Differential Cost of ULN compared to standard low NOx burner) (per Cleaver Brooks)		$100,000
b	Taxes and Freight	(EC*0.05)	$5,000
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 Installation Costs (based on differential cost)

a.	Engineering and Supervision	(TEC*0.1)	$10,500
b.	Construction/Field Expenses	(TEC*0.05)	$5,250
c.	Construction Fee	(TEC*0.1)	$10,500
d.	Start up	(TEC*0.02)	$2,100
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**

Capital Recovery		**$21,907**

Direct Operating Costs

Direct Operating Costs are assumed to be the same for ULN compared to standard low-NOx burner

Indirect Operating Costs (based on differential cost)

a.	Overhead (60% of OL+ML)	$0
b.	Property Tax: (TCC*0.01)	$1,344
c.	Insurance: (TCC*0.01)	$1,344
d.	Administration: (TCC*0.02)	$2,688
Total Indirect Operating Cost		**$5,376**

Total Annual Cost	$27,283
NOx Reduction (tons/yr)	6.57
Cost of Control ($/ton - NOx)	$4,153