December 21, 2012

Mr. James Belsky, Permit Chief
MassDEP Northeast Region
205B Lowell Street
Wilmington, MA 01887

Re: ***Major Comprehensive Plan Approval Application – Salem Harbor Redevelopment Project (Transmittal Number X254064)***

Dear Mr. Belsky:

On behalf of Footprint Power Salem Harbor Development LP, enclosed please find two copies of a Major Comprehensive Plan Approval Application for the Salem Harbor Redevelopment Project at 24 Fort Avenue in Salem. A pre-application meeting for the project was held with you on June 7, 2012.
.
If you have any questions, please contact Mr. George Lipka (who has provided the P.E. stamp on the application) at (617) 443-7568, or me at (617) 803-7809.

Sincerely,

Keith H. Kennedy

Keith H. Kennedy
Senior Consultant – Energy Programs

Enclosures

Comprehensive Plan Approval Application

Salem Harbor Redevelopment Project
Salem, Massachusetts

Submitted to:
Massachusetts Department of Environmental Protection
Northeast Region
205B Lowell Street
Wilmington, MA 01887

Prepared on Behalf of:
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5.0 CONTROL TECHNOLOGY ANALYSIS

This section presents the LAER and BACT analyses for the proposed SHR Facility. In accordance with 310 CMR 7.02, the Project is subject to BACT for all pollutants. The Project will also exceed PSD significant emission thresholds for NO_x, CO, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG, and thus is subject to BACT under this program. Since potential NO_x emissions will also exceed the major source threshold of 50 tons per year under nonattainment new source review (310 CMR 7.00 Appendix A), the Project is also subject to the more stringent LAER requirements for NO_x and compliance with LAER requirements will satisfy BACT requirements for NO_x.

In accordance with 310 CMR 7.00, BACT is defined as "an emission limitation based on the maximum degree of reduction of any regulated air contaminant emitted from or which results from any regulated facility which the Department MassDEP), on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques for control of each such contaminant. The best available control technology determination shall not allow emissions in excess of any emissions standard established under the New Source Performance Standards, National Emissions Standards for Hazardous Air Pollutants or under any other applicable section of 310 CMR 7.00, and may include a design feature, equipment specification, work practice, operating standard or combination thereof" (310 CMR 7.00 Definitions).

The MassDEP requires a "top-down" approach to BACT analysis. The process begins with the identification of control technology alternatives for each pollutant. Technically infeasible technologies are eliminated and the remaining technologies are ranked by control efficiency. These technologies are evaluated based on economic, energy and environmental impacts. If an alternative, starting with the most stringent, is eliminated based on these criteria, the next most stringent technology is evaluated until BACT is selected.

The following control technology analysis encompasses both combustion turbine models currently under consideration for the Project. Section 5.1 addresses the control technology assessments for the combustion turbines. Section 5.2 addresses the control technology assessments for the auxiliary boiler and Section 5.3 addresses the assessments for the emergency generator and fire pump engines. The control technology analyses for each pollutant have been conducted in accordance with EPA "top down" BACT guidance and MassDEP guidance (June 2011) and precedent.

5.1 Combined Cycle Combustion Turbines

5.1.1 Lowest Achievable Emission Rate Analysis for NO_x

As stated previously, the SHR Project is a major new source of NO_x emissions under Appendix A of 310 CMR 7.00 and the Project is therefore subject to LAER controls for NO_x.

In accordance with MassDEP regulations, LAER is defined as "the more stringent rate of emissions based on the following:

- The most stringent emissions limitation which is contained in any state SIP for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

- The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within a stationary source."

Sources Reviewed & Selection of LAER

When determining LAER for a particular project, the initial steps are much the same as a "top down" BACT analysis. In a "top-down" BACT analysis, all possible control technologies are identified and ranked from the top level of control to the bottom and evaluated based upon several criteria. However, in a LAER analysis only the top level of control is considered.

In order to identify the "most stringent emissions limitation which is achieved in practice" by an "F" Class combined cycle combustion turbine facility, numerous sources of information were evaluated. These sources included both state and federal resources of publicly available air permitting information. States that contain significant areas that are non-attainment for ozone, including California, New York, New Jersey, Connecticut, and Massachusetts were the focus for state specific determinations and guidance. The following sources of information were evaluated to determine LAER:

- EPA's RACT, BACT, LAER Clearinghouse (RBLC);
- MassDEP's BACT Guidance of June 2011 including Top Case BACT Guidelines for Combustion Sources;
- EPA Region IV's National Combustion Turbine List;
- The California Air Resources Board (CARB) BACT Clearinghouse;
- The California South Coast Air Quality Management District's (SCAQMD) BACT guidelines;
- State environmental program websites;
- New Jersey's State Of The Art (SOTA) Manual for Stationary Combustion Turbines; and
- The California Energy Commission Energy Facilities Siting Board.

In addition to these sources of information, additional publicly available information obtained through Tetra Tech's experience, such as permits for individual projects not listed in the RBLC or other sources, was also included in the analysis.

Reduction in NO_x emissions can be achieved using combustion controls and/or flue gas treatment. Available combustion controls include dry low-NO_x (DLN) combustors that can be employed during either water or steam injection. The most common post combustion flue gas treatment for combustion turbines is selective catalytic reduction (SCR). Recent combustion turbine projects with a generating capacity of greater than 100 MW have been permitted to utilize SCR to achieve the permitted NO_x emission levels. Accordingly, the Project is proposing to use state of the art DLN combustors in combination with SCR to control NO_x emissions. This combination of controls provides the top level of NO_x emission control for large combustion turbine projects and represents LAER.

DLN combustors are designed to minimize NO_x emissions from the combustion turbine. SCR is placed in the exhaust of the combustion turbine to further lower emissions. SCR reduces NO_x to nitrogen (N_2) and water (H_2O) in the presence of a catalyst and ammonia.

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

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

Based on review of all available data, SCR has been determined to control NO_x emissions down to the lowest possible emission rates. SCR is a reliable control technology with a long track record on “F” Class combustion turbines. No other control technology has successfully been used to achieve low NO_x emissions on large combustion turbines. The LAER emission limit is proposed to be 2.0 ppm corrected to 15% O_2 based on MassDEP’s Top Case BACT values for large combustion turbines.

5.1.2 Best Available Control Technology Assessment for Volatile Organic Compounds

Volatile Organic Compounds VOC are emitted from combustion turbines as a result of incomplete oxidation of the fuel. VOC emissions from combustion turbines can be minimized by the use of proper combustor design and good combustion practices. Depending upon the species of VOCs in the turbine exhaust, an oxidation catalyst may further reduce emissions. An oxidation catalyst is a passive reactor that consists of a honeycomb grid of metal panels coated with a platinum catalyst that is placed in the HRSG in the exhaust gas path.

The SHR Project is proposing to incorporate an oxidation catalyst in order to implement the top level of control to achieve BACT for CO emissions (see Section 5.1.3 below). This system will also reduce VOC emissions but the amount of reduction is expected to be modestl. Nevertheless, the installation of a state of the art combustion turbine equipped with advanced combustion controls and an oxidation catalyst represents the top level of control for VOC emissions from the Project and therefore satisfies the top case for BACT. The proposed BACT emission limit for VOC is 1.0 ppmvdc (volume, dry basis, corrected to 15% O_2) without duct firing and 2.0 ppmvdc with duct firing. Duct firing is expected to occur up to a maximum of 720 hours per year The Top Case VOC BACT value in the June 2011 MassDEP Top Case BACT Guidelines is 1.7 ppmvdc. This is based on the Mystic Station Combined Cycle Project, which was approved at 1.0 ppmvdc VOC without duct firing and 1.7 ppmvdc with duct firing. While the VOC numbers for Footprint and Mystic match without duct firing, the vendor guarantee available now with duct firing is 2.0 ppmvdc. The most recent combined cycle project permitted in Massachusetts with duct firing is the Brockton Project, which was approved (in July 2011) at 1.0 ppmvdc without duct firing and 2.5 ppmvdc with duct firing. Therefore, the VOC limits proposed limit for the SHR Facility (1.0 ppmvdc without duct firing and 2.0 ppmvdc with duct firing) are considered to represent BACT.

5.1.3 Best Available Control Technology Assessment for Carbon Monoxide

CO is emitted from combustion turbines as a result of incomplete oxidation of the fuel. CO emissions can be minimized by the use of proper combustor design and good combustion practices. The most stringent CO control technology is a catalytic oxidation system. A catalytic oxidation system can provide 90% nominal reduction in CO emissions. The oxidation catalyst is a passive reactor that consists of a honeycomb grid of metal panels coated with a platinum catalyst. The catalyst grid is placed in the HRSG in the turbine exhaust gas. The Project is proposing to include an oxidation catalyst in order to achieve the top level of control for CO emissions as specified in the June 2011 MassDEP Top Case BACT Guidelines. This BACT level for CO is 2.0 ppmvdc.

5.1.4 Best Available Control Technology Assessment for PM, PM_{10}, and $PM_{2.5}$

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 are presumed to be less than 2.5 microns in size ($PM_{2.5}$). Particulate emissions are minimized by utilizing state of the art combustion turbines firing natural gas since natural gas is the lowest ash-content fuel available. BACT for particulates in a combustion turbine is good combustion practices and the use of natural gas.

5.1.5 Best Available Control Technology Assessment for Sulfur Dioxide (SO_2)

Sulfur dioxide is emitted from the combustion turbines as a result of the oxidation of the sulfur in the fuel. The only practical means for controlling SO_2 emissions from a combustion turbine project is to limit the sulfur content of the fuel. The Project proposes to use natural gas as the only fuel with no oil backup. Natural gas is the lowest sulfur content fuel commercially available and therefore the top level of BACT for the Project. The sulfur content of the natural gas will be limited to 0.5 grains per 100 cubic feet of gas, or approximately 0.0015 lbs SO_2/MMBtu.

5.1.6 Best Available Control Technology Assessment for Sulfuric Acid Mist

H_2SO_4 emissions are generated by the oxidation of sulfur in the fuel. By reducing fuel sulfur content, H_2SO_4 emissions decrease. BACT for H_2SO_4 is the use of natural gas, which has inherently low sulfur content.

5.1.7 Best Available Control Technology Assessment for Ammonia (NH_3)

Ammonia emissions are due to the use of SCR for NO_x control. Ammonia is injected into the SCR in excess of stoichiometric amounts to achieve maximum conversion of NO_x. This means that slightly more ammonia is injected than is physically required to remove the NO_x in the exhaust gas if operating at 100% efficiency. Additional ammonia is required mostly to offset inefficiencies in the mixing of ammonia in the air stream and insufficient residence time for reaction of the NH_3/NO_x mixture across the catalyst. As a result, some of the injected ammonia does not react, passes through the SCR reactor, and is exhausted to the atmosphere. These ammonia emissions are called the "ammonia slip." BACT for ammonia emissions is proper operation of the SCR to minimize ammonia slip to 2.0 ppmvdc. This represents the top case for combined cycle turbines above 10 MW listed in MassDEP's BACT Guidance of June 2011.

5.1.8 Summary of Proposed Criteria Pollutant BACT/LAER Determinations

In accordance with MassDEP's BACT Guidance document dated June 2011, MassDEP has compiled emission limits that may be proposed in lieu of performing a Top-Down analysis. These are limits that MassDEP has approved recently and these limits represent BACT. With regard to natural gas-fired combined cycle combustion turbines >10 MW, the MassDEP Top Case BACT Guidelines for Combustion Sources provides the BACT emission limits listed in Table 5-1.

Table 5-1 Top Case BACT Emission Limits

Pollutant	Emission Limitation	BACT Determination	Control Technology
NO_X	2.0 ppmvd @ 15% O_2	MassDEP Top Case BACT Guidelines for Combined Cycle Turbine > 10 MW (June 2011)	• Dry Low NOx Combustor • SCR • Oxidation Catalyst
NH_3	2.0 ppmvd @ 15% O_2		
CO	2.0 ppmvd @ 15% O_2		
VOC[1]	1.0 ppmvd @ 15% O_2 without duct firing 2.0 ppmvd @ 15% O_2 with duct firing		

[1]The Top Case VOC BACT value in the MassDEP Top Case BACT Guidelines is 1.7 ppmvdc. The vendor guaranteed VOC emission rate with duct firing is 2.0 ppmvdc. MassDEP has more recently approved a similar project (Brockton) for 2.5 ppmvdc. Therefore, Footprint Power is proposing a VOC BACT emission limit of 2.0 ppmvd @ 15% O_2 with duct firing.

With the Mystic Station Redevelopment Project cited as the basis for the Top Case BACT emission limits, Footprint Power proposes lower limits than approved for Mystic Station emission limits for PM/PM_{10} and SO_2 to represent BACT for the SHR Project. The proposed emission limits compared to the Mystic limits are shown in Table 5-2 below.

Table 5-2 Mystic Station BACT Emission Limits

Pollutant	SHR Proposed Emission Limitation	Mystic Station BACT Determination Transmittal Number W004632	Control Technology
PM	≤ 0.009 lbs/MMBtu	0.011 lbs/MMBtu	• Good combustion practices • Natural gas
PM_{10}	≤ 0.009 lbs/MMBtu	0.011 lbs/MMBtu	
$PM_{2.5}$	≤ 0.009 lbs/MMBtu	0.011 lbs/MMBtu	
SO_2	0.0015 lbs/MMBtu	0.0029 lb/MMBtu [1]	
H_2SO_4	0.0010 lbs/MMBtu	0.0016 lb/MMBtu [2]	

[1] Mystic Station SO_2 emission limit is 0.0029 lbs/MMBtu. However, based on the approved gas sulfur content of 0.8 grains per 100 ft^3, the equivalent SO_2 emission limit is 0.0023 lbs/MMBtu.

[2] This value is not in the current Mystic Station Operating Permit, but is referenced in the original PSD Approval (January 2000).

5.1.9 Startup/Shutdown (SUSD) Emissions

Combustion turbines experience increased VOC, CO and NO_x emissions during startup and shutdown due to the non-steady state operations. In addition, low operating temperatures preclude the use of the SCR. BACT for startup and shutdown is good operating practices by following the manufacturer's recommendations during startup, and limiting the startup time. The combustion turbines proposed for the SHR Project are "quick-start" turbines, each capable of approximately 150 MW (300 MW total) within 10 minutes of startup. These quick-start turbines significantly reduce startup emissions compared to older generations which take several hours to reach maximum capacity. The selected combustion turbine will be operated in accordance with manufacturer specifications during SUSD periods in order to ensure that emissions are minimized during these short periods. Additionally, ammonia injection will be initiated as a soon as the SCR catalyst reaches the vendor specified minimum operating temperature and all system permissives are met to minimize NO_x emissions during these periods. The estimated startup/shutdown emissions are provided in Table 5-3.

Table 5-3 Startup and Shutdown Emission Limits (lbs per event)

Pollutant	Startup (duration 45 minutes)	Shutdown (duration 30 minutes)
NO_x	88	60
CO	491	530
VOC	104	46

5.1.10 Best Available Control Technology Assessment for Greenhouse Gases

Unlike guidance for the other key pollutants addressed above, MassDEP has not issued formal Top Case BACT Guidance for GHG. Therefore, EPA BACT guidance has been used for this determination. The BACT process is discussed in detail in the EPA document "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting" , which is not a rule but acts as a non-binding guidance document for EPA, state permitting authorities and permit applicants. In addition to the 1990 EPA guidance document, the BACT analysis pertaining to GHG has been conducted in accordance with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases". Although the 2011 guidance document refers to the same top-down methodology described in the 1990 document, it provides additional clarification and detail with regard to some aspects of the analysis.

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). The only document found with pertinent GHG BACT information was the Pioneer Valley permit data. 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 SHR 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 SHR Facility 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 SHR Facility.

Energy Efficiency and Heat Rate

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, boilers have a higher heat rate than combustion turbines due to the loss of energy in the transfer of heat from combustion to the water tubes. The combustion energy in a turbine is more directly imparted on the turbine blade than a boiler. Combined cycle turbines also use the waste heat from the combustion turbines to generate additional power (utilizing the HRSG).

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 5-1); 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 of energy efficiency and heat rate. The SHR Project is already using the lowest carbon fuel and carbon capture and storage is not currently feasible.

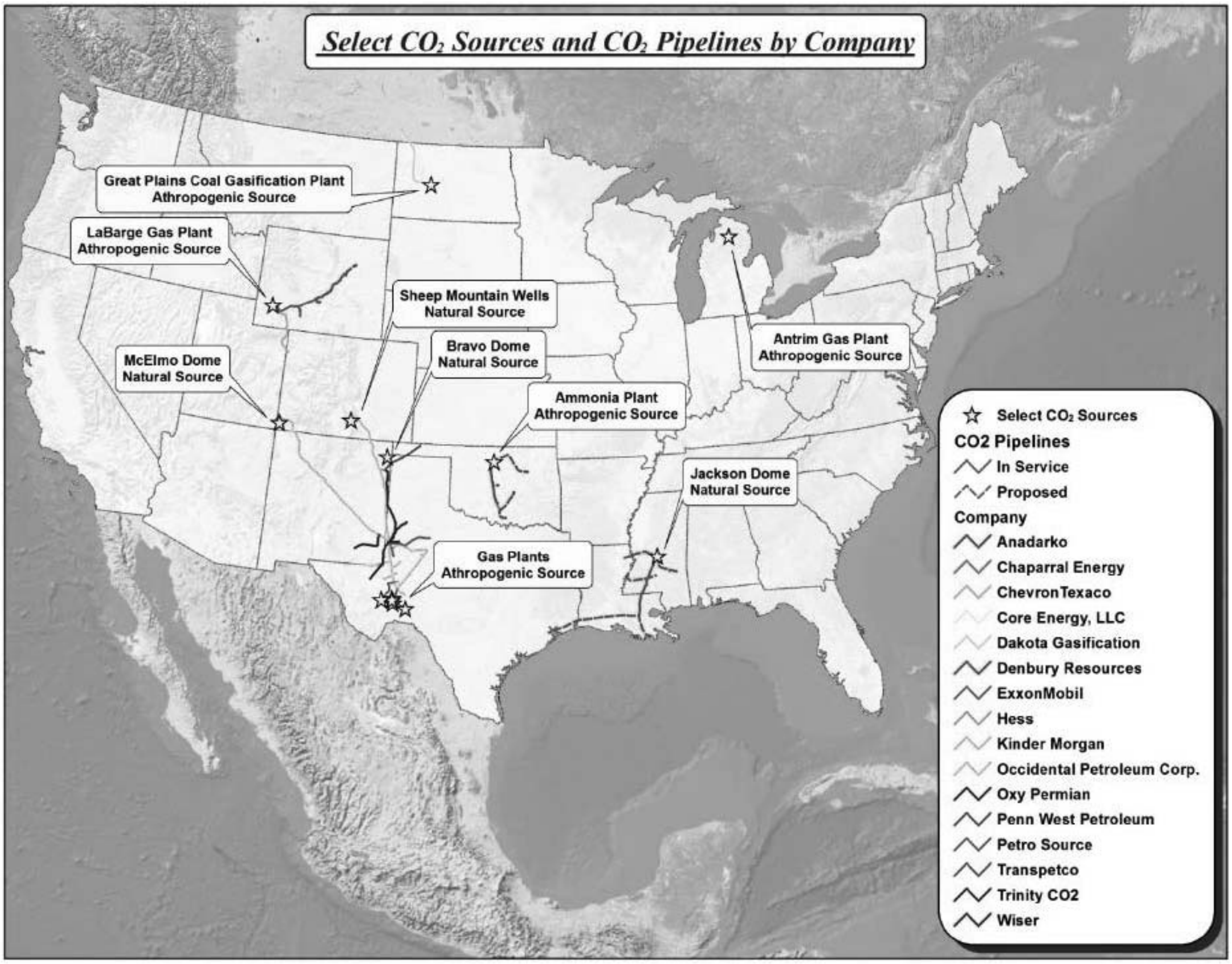

Figure 5-1 CO_2 Pipelines in the United States
From: "Report of the Interagency Task Force on Carbon Capture and Storage," August 2010, Appendix B.)

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) need 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.

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. The most likely candidate source for the volumes required would be the SESD sewage treatment plant. User of seawater for makeup to a wet evaporative system is a very challenging application, but has been done in limited cases. 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 the typical chemical constituents of the effluent and the likely highly variable concentrations of certain of these constituents would place a burden on the CCG Facility. 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.

Step 5: GHG BACT

The very low heat rates (high efficiency) associated with the combined cycle combustion turbine technology selected for the SHR Project and the use of the lowest carbon fossil fuel, natural gas, as the exclusive fuel represent BACT for GHG for this project. Two F series turbines in combined cycle configuration have been determined integral to the project design size of 630 MW. Quick-start capability has been included to increase overall project efficiency.

Footprint Power is proposing an emission limit in lbs of CO_2/MW-hr delivered to the electrical grid (net), to be met during an initial stack test. Since weather conditions, which affect efficiency during a stack test, are unknown at this time, the proposed emission limit is based on International Organization for Standardization (ISO) conditions. ISO 3977-2 sets the standard conditions at 59°F, 14.7 psia, and 60% humidity. Weather conditions during the stack test will be corrected to these ISO values.

Using a maximum design net “new and clean” heat rate at ISO conditions of approximately 7080 Btu/kw-hr_{grid} (based on fuel higher heating value) and a CO_2 emission factor of 118.9 lbs/million Btu provides a “new and clean” GHG emission rate of 842 lbs CO_2/MW-hr_{grid}. Footprint Power believes that CO_2 is a valid surrogate for GHG since greater than 99.9% of all GHG emissions on a CO_2e basis are CO_2. Footprint Power proposes a “new and clean” emission limit of 842 lbs CO_2/MW-hr_{grid}. Since a turbine’s efficiency will degrade with time and fluctuate due to ambient conditions, the emission limit of 842 lbs CO_2/MW-hr_{grid} should apply only during the initial stack test. This test would be done at base load conditions.

5.2 Auxiliary Boiler

The SHR Project will include the installation of an 80 MMBtu/hr heat input, natural gas-fired auxiliary boiler. Annual operation of the auxiliary boiler will be limited to the full load equivalent of 6,570 hrs/yr. The unit will be equipped with ultra-low NO_x burners for NO_x control. Emissions will be controlled through the exclusive use of natural gas as fuel, good combustion practices and a limit on the annual operations. In addition, the auxiliary boiler will meet the emission limits determined by MassDEP to be the Top Case BACT for natural gas fired boiler between 40 MMBtu and 100 MMBtu/hr in size (June 2011) with the exception of PM/PM_{10}/$PM_{2.5}$. The top BACT case listed in the June 2011 MassDEP guidance for natural gas boilers of this size is 0.002 lb/MMBtu which Footprint Power does not believe is feasible as BACT for this application. For PM/PM_{10}/$PM_{2.5}$ Footprint Power is proposing a BACT limit of 0.005 lb/MMBtu.. This BACT limit is more stringent than other recent BACT limits for natural gas fired boilers in Massachusetts. PM BACT limits established relatively recently for auxiliary boilers at Mystic Station and Veolia MATEP are 0.007 lb/MMBtu and for Brockton Power is 0.01 lb/MMBtu. The PM BACT limit for the auxiliary boiler at Pioneer Valley Energy Center is comparable at 0.0048 lb/MMBtu.

The Top Case BACT emission limits for the Auxiliary Boiler are shown in Table 5-8.

Table 5-8 Top Case BACT Emission Limits for the Auxiliary Boiler

Pollutant	Emission Limitation	BACT Determination	Control Technology
NOx	0.011 lbs/MMBtu	MassDEP Top Case BACT Guidelines for Natural Gas Boilers (40-100 MMBtu/hr heat input) (June 2011)	• Ultra Low NOx Burners (9 ppm) • Good combustion practices • Natural gas
$PM/PM_{10}/PM_{2.5}$ [1]	0.005 lbs/MMBtu		
CO	0.035 lbs/MMBtu		
VOC	0.005 lbs/MMBtu		
SO_2 [2]	0.0015 lbs/MMBtu	Plan Approval, Transmittal Number W004632	Natural Gas
H_2SO_4 [3]	0.0010 lbs/MMBtu	2	Natural Gas

1 Top Case BACT for natural gas-fired boilers between 40 and 100 MMBtu/hr in the MassDEP guidance (June 2011) is 0.002 lbs PM/MMBtu.. Footprint Power is proposing a PM/PM10/PM2.5 emission limit of 0.005 lbs PM/MMBtu which is comparable or less than MassDEP values recently approved for new gas-fired boilers.

2 Mystic Station auxiliary boiler SO_2 emission limit is 0.0023 lbs/MMBtu. Based on the gas sulfur content of 0.5 grains per 100 ft^3, the proposed SO_2 emission limit is 0.0015 lbs/MMBtu.

3 Assumed to be equivalent to 2/3 of SO_2 emissions based on vendor data. No H_2SO_4 emission limit cited in Mystic Station air permit.

5.3 Emergency Generator and Fire Pump Engines

The Project will include an emergency diesel generator (EDG) engine and a diesel fire pump (FP). Both engines will operate on Ultra Low Sulfur Diesel (ULSD) fuel. The proposed EDG will be a Cummins 750DQFAA ULSD-fired engine (or equivalent) with a standby generating capacity of 750 kW. The FP engine will be a 371 BHP, 2.7 MMBtu/hr ULSD-fired engine. Both engines will be used in emergency situations only (with the exception periodic maintenance/testing events) and will be limited to a maximum of 300 hours per rolling 12 month period of operation. There are no post-combustion controls that have been demonstrated in practice for small, emergency internal combustion engines. In order to satisfy LAER/BACT requirements, Footprint Power proposes that the EDG will meet the Tier 2 standards and the FP will meet Tier 3 standards for off-road diesel engines. These both meet requirements specified under 40 CFR 89 as is specified in in MassDEP's Air Pollution Control Regulation at 310 CMR 7.26(42)(b) and represent the Top Case under MassDEP's June 2011 BACT Guidelines. Emissions will be controlled through the use of ULSD, good combustion practices and limited annual operation. With the exception of emergency situations, the units will typically operate no more than one hour per week, for testing and maintenance purposes. The specific EDG and FP BACT/LAER emission limits are shown in Tables 5-9 and 5-10.

Table 5-9 EDG Emission Standards

Pollutant	Tier II Standard	Emissions (lbs/hr)	Emissions (tpy)
NO_x [1]	6.4 g/kWh	11.60	1.74
CO	3.5 g/kWh	6.35	0.95
VOC [1]	1.3 g/kWh	2.36	0.35
$PM/PM_{10}/PM_{2.5}$	0.2 g/kWh	0.42 [2]	0.06 [2]
SO_2 [3]	NA	0.011	0.002

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

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

3 There is no Tier 2 limit for SO_2 emissions, SO_2 emissions are limited based upon fuel sulfur content of 15 ppm (0.0015 lb/MMBtu).

Table 5-10 FP Emission Standards

Pollutant	Tier III Standard	Emissions (lbs/hr)	Emissions (tpy)
NO_x[1]	4.0 g/kWh	2.44	0.37
CO	3.5 g/kWh	2.14	0.32
VOC[1]	1.3 g/kWh	0.79	0.12
$PM/PM_{10}/PM_{2.5}$	0.2 g/kWh	0.14[2]	0.02[2]
SO_2[3]	NA	0.004	0.0006

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

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

3 There is no Tier 2 limit for SO_2 emissions, SO_2 emissions limited based upon fuel sulfur content of 15 ppm (0.0015 lb/MMBtu).

APPENDIX C

Equipment Specifications and Vendor Performance Data

Total Estimated Startup & Shutdown Emissions and Fuel Use - 1x1 SCC6-5000F(5) ULN Flex-Plant^{TM} 30 on Natural Gas with Drum HRSG and ACC @ 59 °F

Mode	Time (min)	Total Pounds Per Event					
		NO_X	CO	VOC	SO_2	PM	Fuel Use
"Cold" Startup (GT Ignition to Emissions Compliance @ 60% GT Load)	45	83	327	104	1.1	6.4	30,980
"Cold" Startup (GT Ignition to 100% GT Load)	279	125	352	115	9.9	38	277,836
"Cold" Startup (GT Ignition to ST VWO)	280	126	352	115	9.9	38	279,438
"Warm" Startup (GT Ignition to Emissions Compliance @ 60% GT Load)	45	79	230	89	1.1	6.0	31,145
"Warm" Startup (GT Ignition to 100% GT Load)	124	94	238	93	4.1	17	115,241
"Warm" Startup (GT Ignition to ST VWO)	129	95	239	93	4.4	18	123,251
"Hot" Startup (GT Ignition to Emissions Compliance @ 60% GT Load)	35	58	172	66	0.9	5.1	24,613
"Hot" Startup (GT Ignition to 100% GT Load)	87	68	177	69	2.8	12	79,715
"Hot" Startup (GT Ignition to ST VWO)	87	68	177	69	2.8	12	79,715
Shutdown (70% GT Load to Fuel Cut Off)	10	20	61	24	0.2	1.8	6,865
Shutdown (100% GT Load to Fuel Cut Off)	84	34	68	28	3.1	12	86,394

General Notes

1.) All data is ESTIMATED, NOT guaranteed and is for ONE unit (gas turbine and HRSG).
2.) Emissions are at the HRSG exhaust stack outlet and exclude ambient air contributions.
3.) Emissions are based on new and clean conditions.
4.) VOC consist of total hydrocarbons excluding methane and ethane and are expressed in terms of methane (CH_4).
5.) SO_2 emissions are based on 0.5 gr S/100 scf in the natural gas.
6.) Particulate (PM) emissions are based on the aforementioned fuel sulfur content and are per USEPA Methods 5/202.
7.) Gas fuel composition is 98% CH_4, 0.6% C_2H_6, 1.4% N_2 and ~ 0.5 grains S/100 SCF.
8.) Fuel use is based on a fuel heating value of approximately 23,300 Btu/lb_m (HHV).
9.) Gas fuel must be in compliance with the Siemens fuel specification.
10.) Please be advised that the information contained in this transmittal has been prepared and is being transmitted per customer request specifically for information purposes only. Such information is not intended to be used for evaluation of plant design and/or performance relative to contractual commitments. Data included in any permit application or Environmental Impact Statement is strictly the customer's responsibility. Siemens is available to review permit application data upon request.

Startup / Shutdown Emissions Notes

1.) "Cold" startup (SU) data are based on an extended gas turbine (GT) shutdown (SD), greater than ~ 64 hours, with the steam turbine (ST) HP/IP metal casing temperature less than ~ 428 °F / 518 °F.
2.) "Warm" SU data are based on the GT being shutdown between ~ 16 and 64 hours, with the ST HP/IP metal casing temperature between ~ 428 °F / 518 °F and 626 °F / 626 °F.
3.) "Hot" SU data are based on the GT being shutdown less than ~ 16 hours, with the ST HP/IP metal casing temperature greater than ~ 626 °F / 626 °F.
4.) Estimated data are based on the assumed times noted above (per "FP30-1x1-5000F-SST900(HP16+C372)6MW_SFC-SDAB LDF-ACC FG (drum) REV 005exp.pdf" dated May 11, 2011) and will be higher for longer times.
5.) Estimated emissions data are based on an ambient temperature of 59 °F and will be higher at lower ambient temperatures.
6.) Estimated NO_X emissions assume the use of an SCR system from 60% GT load (+10 min. SCR warmup) and above for SU, and from 100% to 60% GT load during SD.
7.) CO and VOC emissions estimates assume the use of an oxidation catalyst.
8.) "Emissions Compliance" assumed to mean 2 ppmvd NO_X and 2 ppmvd CO at the stack.
9.) Steam chemistry adequate for ST operation (no waiting time included).
10.) Data assumes all BOP systems and auxiliaries meet start prerequisites and that all systems run smoothly without upsets.
11.) Operator actions do not extend SU or SD times.
12.) Auxiliary cooling systems running as needed.
13.) Auxiliary boiler sized to supply pegging steam to HRSGs and seal steam to ST.
14.) Air-Cooled Condenser (ACC) sizing allows partial and full bypass operation at up to 60% GT Load and 2x1 operation without violating the condenser back pressure limits.
15.) HRSG stack damper has been closed as soon after SD as possible to maintain heat, and HRSG has been maintained in a "bottled-up" condition during the SD.
16.) It is assumed that there is no restriction from the interconnected utility for loading the GT within the SU times considered.
17.) CEMS may calculate emissions differently.