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March 9, 2011

Mr. Donald Dahl
United States Environmental Protection Agency
1 Congress Street
Suite 1100
Mail Code: CAP
Boston, Massachusetts 02114-2023

RE: Pioneer Valley Energy Center – Westfield, Massachusetts
Prevention of Significant Deterioration Application
Best Available Control Technology Analysis for Greenhouse Gas Emissions

Dear Mr. Dahl:

In response to your request, ESS Group, Inc. ("ESS") is providing this supplemental information concerning the above referenced project ("the Project") to support a determination that the greenhouse gas ("GHG") emissions control measures which will be employed represent Best Available Control Technology ("BACT"). This letter provides a "top-down" analysis of potentially viable GHG emissions control technologies which concludes that the use of natural gas as the primary fuel, in conjunction with the highly efficient combined cycle gas turbine equipment and overall generating facility design, constitute BACT for the Project.

TOP-DOWN BACT ANALYSIS APPROACH

The determination of BACT is made through a "top-down" analysis of potentially viable control technologies starting with the approach that provides the greatest level of emission control. Technologies that result in higher emissions can only be considered if the more efficient control technology evaluated is determined to be either technically or economically infeasible. BACT is defined by EPA in 40 CFR 52.21 as follows:

> "Best available control technology means an emission limitation 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 in excess of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61."

Thus, a BACT analysis is a project specific assessment of technical, environmental, and economic impacts of applying various emission control options. BACT review is a "top-down" method for determining the best available control technology. In general, a top-down

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approach requires that all available control technologies be ranked in descending order of control effectiveness. The control technology examined and recommended as the most effective is considered the most stringent technology or BACT, unless technical considerations, energy requirements or economic considerations justify that the top technology is not feasible or achievable.

The following steps are followed in this BACT top-down analysis:

Step 1 - Identify All Control Technologies

Step 2 - Eliminate Technologically Infeasible Options

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Step 4 - Cost Effectiveness Analysis

Step 5 - Select BACT

The universe of potential emissions control options is first identified and each option is evaluated for its technical feasibility. Options found to be technically feasible are ranked by control efficiency. In the event the most stringent level of control is ruled out due to cost, energy consumption, or environmental impacts, the next most stringent level of control is analyzed until BACT is determined. An analysis of other control technologies is not necessary if the technology proposed is the highest level of control found technically feasible.

BASIS OF THE PROJECT

In order to properly assess potentially applicable GHG emissions control technologies, it is important to understand the developer's basis and business model for the Project. Pioneer Valley Energy Center, LLC ("PVEC"), an affiliate of Energy Management, Inc., has proposed to develop a fossil fuel fired electric generating facility that will sell its power into the commercial and municipal markets within the control area managed by the Independent System Operator for New England ("ISO-NE"). PVEC is a special purpose entity formed specifically to develop this energy generating project. Recognizing the ongoing need for readily dispatchable generation to service intermediate load, PVEC's business plan does not involve the development of renewable energy generation such as wind or solar, nor does it involve development of load-reducing, demand response resources. PVEC also recognizes the studies related to biomass generation sponsored by the Commonwealth of Massachusetts and the proposed regulatory changes related to biomass fueled bulk power generation. The resulting ongoing uncertainty, which present significant barriers to development, has caused PVEC to preclude this fuel from its Project design. Rather, PVEC's business plan calls for using fuels that are readily available, commercially demonstrated for the selected generating technology, and resulting in the lowest overall emissions feasible.

PROJECT GHG EMISSIONS

The attached Table 1 summarizes the maximum greenhouse gas emissions from the Project. It includes a summary of the maximum hourly, daily, and annual GHG emissions from the combustion turbine (while firing natural gas and while firing ULSD), the auxiliary boiler, the emergency generator, and the diesel fire pump.

The GHG emissions have been determined based on the respective fuel heating value, the maximum heat input rate, and the permitted hours of operation for each source. The maximum GHG emission rates are presented in CO_2 equivalents (CO_{2e}), as the sum of each source's carbon dioxide, methane, and nitrous oxide emissions, each weighted by their respective global warming potential (GWP). The references for the GHG emissions factors used for this determination are summarized on Table 1.

IDENTIFICATION OF POTENTIAL CONTROL TECHNOLOGIES

To aid in identifying GHG emissions control technologies deemed as BACT for similar sources, determinations established by various state agencies and the EPA were reviewed. Sources of information included the USEPA's RACT/BACT/LAER Clearinghouse (RBLC) and GHG Mitigation Measures Database, the South Coast Air Quality Management District BACT determinations, the California Air Resources Board's BACT Clearinghouse Database, and any available recently issued air permits. None of these databases or publicly available permits provided any relevant information regarding GHG emissions control technologies[1] for the Project. However, a review of the Bay Area Air Quality Management District's website did identify a PSD permit issued in February, 2009 to the Russell City Energy Center which addressed BACT for the facility's GHG emissions[2]. In the documents supporting that permit, the Air District determined that at the present there are no feasible post-combustion add-on controls and the only feasible control technology for reducing greenhouse gas emissions from fossil fuel energy generating facilities is to use the most efficient electrical generating technology available for the proposed project design.

ESS' review of applicable MassDEP and USEPA emissions regulations also did not identify any specific emissions limitations that apply to the Project. As discussed in Section 4.3 of the Prevention of Significant Deterioration ("PSD") application filed for the Project, the Project will be subject to the Carbon Dioxide Budget Program established in the Massachusetts Air Pollution Control Regulations (310 CMR 7.70), which will require the owner/operator to acquire allowances annually equal to the tons of carbon dioxide emitted in each specified 3-year control period. The Project's GHG emissions have also undergone thorough review

[1] This is not an unexpected outcome, given that BACT evaluations for GHG emissions under the Clean Air Act and ensuing regulations were not required prior to 2011.
[2] See: http://www.baaqmd.gov/Home/Divisions/Engineering/Public%20Notices%20on%20Permits/2010/020410%2015487/Russell%20City%20Energy%20Center.aspx

under the Massachusetts Environmental Policy Act ("MEPA") Greenhouse Gas Emissions Policy and Protocol ("the GHG Policy"), which requires specified projects to identify measures to avoid, minimize, or mitigate those emissions. Following this review, the Secretary of the Massachusetts Executive Office of Energy and Environmental Affairs concluded that the Project's design and operation, as well as the developers commitment to implement an innovative, small-scale hydropower generation project as an additional measure to mitigate its GHG emissions, satisfied the requirements of the GHG Policy.

ESS also reviewed technical data provided by various combustion turbine manufacturers, the U.S. Department of Energy National Energy Technology Laboratory, the U.S. Energy Information Administration, and various technical papers summarizing research and development of GHG emissions control technologies. These resources identified GHG emission control technologies that fall into three categories: 1) using efficient generating technology; 2) selection of inherently lower emitting fuels; and, 3) installation of add-on controls. Each of these technologies is discussed below.

Efficiency

Several information sources, including EPA's recently issued "PSD and Title V Permitting Guidance for Greenhouse Gases" recognize that GHG emissions from electric generating facilities can be most effectively minimized by using highly efficient power generating equipment and by optimizing the energy efficiency of the overall generating facility design. Such equipment minimizes the quantity of GHG emissions generated per unit of net power produced by minimizing the quantity of fuel combusted, as well as the quantity of power consumed by the generating facility itself. The best measure of the overall generating facility efficiency is the "net heat rate", defined as the ratio of total energy input divided by the quantity of power distributed to the electric supply grid.

The Project has optimized its net heat rate primarily through the use of the most advanced combined cycle combustion turbine technology available to produce on the order of 400 MW of power while using the lowest quantity of fuel. In addition, PVEC studied both wet and dry cooling technologies for the Project and determined that the use of wet cooling technology, supplied by a vast and currently unused water supply resource, further improved overall efficiency by approximately 3%, resulting in a reduction of approximately 90,000 tons of carbon dioxide emissions per year. Overall, the design net heat rate of the Project's power island is 5,948 Btu per kilowatt-hour (Btu/kWh)[3].

Review of published data available from leading turbine manufacturers such as General Electric and Siemens indicates that the most advanced machines have similar or higher heat rates as shown in table below.

[3] Based on annual average temperature in the project area and use of natural gas fuel with a lower heating value of 925 Btu per cubic foot.

TURBINE MANUFACTURER	MODEL	POWER OUTPUT (MW)	HEAT RATE (Btu/kWh)
GE[4]	MS7001FB	280	5,950
	MS7001FA	263	6,090
SIEMENS[5]	SCC6-5000F	293	5,990

The GHG emissions related to the Project have also been minimized by:

- Using high-efficiency HVAC systems
- Eliminating or reducing the amount of refrigerant used in HVAC systems
- Incorporating window glazing to optimize heat loss
- Incorporating super insulation to minimize heat loss
- Incorporating motion sensors for lighting and climate control
- Installing a water turbine in the cooling water supply line

As indicated above, the Project will utilize among the most efficient generating technologies and overall facility designs available to minimize GHG emissions.

The Project net heat rate cited above is the design basis heat rate, or the thermal efficiency for which the Project was designed. For the Russell City Energy Center PSD GHG BACT analysis, the Air District evaluated factors that could potentially cause the facility over time to operate at a lower thermal efficiency, and therefore at a higher heat rate than the design rate. The purpose of this evaluation was to ensure that the BACT heat rate incorporated a sufficient margin for maintaining compliance over the full operating range and operational life of the facility.

For the Russell City Energy Center, the Air District incorporated the following factors in determining the compliance margin for the BACT heat rate:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
- A 6% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

[4] See http://www.gepower.com/prod_serv/products/gas_turbines_cc/en/downloads/gasturbine_cc_products.pdf
[5] See: http://www.energy.siemens.com/mx/pool/hq/power-generation/power-plants/gas-fired-power-plants/combined-cycle-powerplants/A96001-S90-A192-V2-4A00.pdf. Note that the Siemens SCC6-60001G machine shown in the brochure is no longer commercially available.

To be consistent with the Russell City Energy Center GHG BACT analysis, and to ensure a sufficient margin for compliance, PVEC proposes the following adjustments to its design heat rate to determine the BACT heat rate limit for the Project:

- 3% design margin
- 6% performance margin
- 6% degradation margin

PVEC is proposing these margins, which are consistent with industry standards, after consultation with the equipment manufacturer on the expected performance of the turbine and auxiliary equipment over time. As a result of these adjustments, PVEC is proposing a BACT heat rate for the Project of 6,840 Btu/kWh. This rate is approximately 11.5% lower than the BACT heat rate proposed for the Russell City Energy Center (7,730 Btu/kWh), and thus represents the lowest BACT heat rate proposed to date for a combined-cycle energy facility PSD Permit.

Fuel Selection

Given the Project's basis and business model as summarized above, along with the selection of highly efficient combined cycle combustion turbine technology, potentially available fuels include natural gas, synthetic gas produced from coal, distillate fuel oil, and low carbon biofuel. According to published EPA emissions factors, natural gas and number 2 distillate fuel oil result in potential carbon dioxide emissions of 117 and 159 pounds per million Btu of heat input (lbs/MMBtu), respectively. Both fuels are readily available from regional distribution systems and providers. Alternatively, Integrated Gasification Combined Cycle (IGCC) projects are being developed which use a coal gasification system to produce synthetic gas ("syngas"). Although combusting the raw syngas would result in similar GHG emissions as combusting coal itself, technologies have been developed to remove most of the carbon contained in the syngas prior to combustion, resulting in even lower emissions than natural gas (see discussion of add-on control technologies below). Advanced biofuels are being developed that may be considered "carbon neutral" when overall life-cycle carbon emissions, including carbon dioxide sequestration that occurs during growth of the biomass feedstock used to produce the fuel, are considered.

PVEC has proposed to fuel the Project predominantly with natural gas due its inherently low emissions characteristics, commercial availability, and demonstrated viability as discussed further below.

Add-On Controls

The two primary methods of abating carbon dioxide emissions from fossil fuel fired electric generating facilities involve removal of carbon from the fuel prior to combustion and scrubbing of carbon dioxide from the combustion system exhaust. These techniques are commonly referred to as "carbon capture and sequestration" ("CCS"), as once the carbon is removed it must be permanently stored (i.e. sequestered) to prevent it from entering the atmosphere.

Removing carbon from the fuel prior to combustion is a technique being employed for IGCC facilities, where the syngas produced is passed through a water-gas shift reactor to convert carbon monoxide in the syngas to carbon dioxide, and then scrubbing the syngas to remove the carbon dioxide. The carbon dioxide is stripped from scrubbing liquid, compressed, and injected into deep geologic formations for permanent storage. Captured carbon dioxide streams are being usefully employed in the mid-west region of the U.S. through injection into oil wells for enhanced oil recovery ("EOR") from nearly depleted wells. Carbon dioxide injection to formations that exist deep below the sea bed is currently being employed in the North Sea.

Methods to remove carbon dioxide from a combustion system's exhaust stream using a similar wet scrubbing technique as the syngas cleanup method discussed above for IGCC facilities are also under development. A variety of alkanolamine solutions are being evaluated as scrubbing liquids as the carbon dioxide can be stripped from the liquid and it can be reused in the scrubbing system. Similar to IGCC systems, the stripped carbon dioxide must be compressed and sequestered in underground geologic formations or EOR operations.

ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL TECHNOLOGIES

As noted above, PVEC has committed to employing one of the most highly efficient combined cycle combustion turbines available, using low emitting natural gas as its primary fuel, and equipping the overall generating facility with low emitting and efficient auxiliary equipment. However, PVEC does not believe that the other identified control technologies are technically feasible, as summarized below.

Biofuels

As discussed in the MEPA filings for the Project, the use of low carbon biofuels in combustion turbines is in the early evaluation and development stage. In the past few years, there have been several tests of biofuels in stationary gas turbines. The most extensive publication of results comes from a test performed by GE Energy and Group E, a power producer in Switzerland. A 2-day test was conducted on a 40MW GE Frame 6B gas turbine. The unit was tested while operating using various concentrations of biofuel, using various fuel configurations (including co-firing with natural gas), and at various operating loads. The emissions on biofuel were determined to be moderately lower than on conventional distillate, although particulate emissions were not measured directly. The results of the test were published in the Proceedings of ASME Turbo Expo in 2007 as GT2007-27212. In July of 2007 GE and Duke Energy conducted several days of biofuel testing on a 7EA peaker facility near

Blacksburg, South Carolina. Initial indications in the press showed a positive test, but final results have not yet been published by GE.

Biofuels could in many ways be a more desirable fuel for use in combustion turbines than conventional distillate fuel. Because the fuel is not derived from underground fossil fuels, there are fewer heavy metal contaminants, which can be detrimental to the hot gas passes of a combustion turbine. The decrease in non-combustibles should also result in lower overall particulate emissions. The GE test results from Switzerland indicate that increased NO_x emission levels might not be a problem, unlike in diesel engines. Much of the research done indicates that biofuels are inherently cleaner-burning than distillates.

Nonetheless, there remain numerous technical barriers to the prolonged use of biofuels in large stationary gas turbines. One such barrier is the catalyst used in the trans-esterification process which converts vegetable oil into biofuel. The most common catalyst material used is sodium or potassium hydroxide, which can result in sodium or potassium contamination of the final product. Sodium and potassium can cause spalling of the thermal barrier coating used to protect the highest-temperature components of a combustion turbine, making them highly undesirable constituents of combustion turbine fuel. Most major GT manufacturers limit the combined sodium and potassium content to less than 1 ppm. In testing performed for another project, it has been demonstrated that this is achievable. However, this was a spot test and it remains to be demonstrated that it is achievable on a long-term basis. The current ASTM specification for biodiesel (ASTM D6751-07b) has a limit of 5 ppm for combined sodium and potassium. This issue will need to be addressed by the biofuel production industry before the product can be accepted by gas turbine manufacturers for use in their machines.

Another characteristic of biofuel that presents a barrier to use in large-scale power generation is the tendency of the fuel to turn into a semi-solid gel at low temperatures. The entire fuel storage and delivery system of the combustion turbine would need to be re-engineered to address this issue. At a minimum, storage tanks will need external heaters. Biofuel also de-stabilizes over long periods of exposure to oxygen, necessitating nitrogen blankets on fuel storage tanks, and the fuel can be aggressive to some polymers commonly used in gaskets and o-rings.

Large-scale generating facilities such as the proposed Project typically require performance guarantees and Long-Term Service Agreements (LTSA's) from the original equipment manufacturers (OEM's) in order to get construction financing. The risk of major component failure is borne by the OEM. Until significant long-term testing of biofuels in modern engines is carried out, the OEM's are unlikely to take on the significant financial consequences associated with such a risk.

Syngas

In order to utilize a syngas fuel stream for the Project, a complete gasification system with coal transportation and storage systems and CCS technology would need to be developed.

Sequestration of the captured carbon dioxide would require development of a high pressure pipeline several hundred miles long to transport the material to a location with viable geologic formations, which are not present in the Project area. In addition to the major technical barriers, these factors would dramatically redesign the overall Project and would conflict with PVEC's basis and business plan for the energy facility. The use of syngas fuel is therefore not feasible for the Project.

Add-On Controls

The USEPA's Greenhouse Gas Mitigation Measures Database[6] describes post combustion flue gas scrubbing using amine solutions, followed by deep geologic sequestration as being in the "pilot" stage. Even if the technologies were commercially viable and demonstrated in practice at the scale of the Project, their application would require the development of a sequestration system. The technical barriers to the development of such a system are discussed above. The use of add-on controls for GHG emissions reduction is therefore not technically feasible for the Project.

AUXILIARY EQUIPMENT

Auxiliary Boiler

The auxiliary boiler for the Project will be fired by natural gas fuel, will utilize efficient combustion technology, and will be limited in operation to 1,100 hours per year. There are no add-on controls for GHG emissions which are currently technically feasible for boilers. Control of GHG emissions from boilers is achieved by burning clean fuels, optimizing the combustion technology to minimize the amount of fuel used during operation, and by minimizing operation of the boiler.

The use of biofuels in the Project auxiliary boiler is not technically feasible due to the same issues raised previously concerning biofuel use in the combustion turbine. Natural gas is the cleanest burning fuel available for the auxiliary boiler. The use of natural gas fuel, efficient combustion technology, and limited operation are the highest levels of GHG control available and therefore represent BACT for GHG for the auxiliary boiler.

Emergency Generator & Fire Pump

The emergency generator and fire pump for the Project will be fired by ULSD fuel and will utilize engines certified to meet the strictest EPA Tier 3 emission standards. They will also each be limited in operation to 300 hours per year. There are no add-on controls for GHG emissions which are currently technically feasible for diesel engines. Control of GHG emissions from diesel engines is achieved by burning clean fuels, optimizing the combustion

[6] See: http://ghg.ie.unc.edu:8080/GHGMDB/

technology to minimize the amount of fuel used during operation, and by minimizing operation of the engines.

The use of natural gas fuel in the Project standby engines is not feasible because of the need for reliability in cases where the natural gas supply is unavailable. The use of biofuels in the standby engines is not technically feasible, for the reasons previously described. ULSD is the cleanest burning fuel available for the Project standby engines. By utilizing standby engines that meet the strictest EPA Tier 3 emission standards, PVEC is ensuring that the standby engines will utilize the most efficient combustion technology available for such sources.

The use of ULSD fuel, Tier 3 certified engines, and strict operational limits are the highest levels of GHG control available and therefore represent BACT for GHG for the Project emergency generator and fire pump.

Circuit Breakers

The Project circuit breakers will have the potential for fugitive emissions of sulfur hexafluoride (SF_6) via leaks. PVEC has investigated the potential use of other materials in the circuit breakers, including dielectric oil or compressed air, which have historically been used in high-voltage circuit breakers prior to the development of SF_6 circuit breakers. The use of circuit breakers with these materials is technically feasible for the Project; however their use would require significantly larger equipment to achieve comparable performance as SF_6 circuit breakers. Because of space constraints on the Project site, the use of circuit breakers containing these materials, although technically feasible, is not an available control technology for the Project. There are ongoing research efforts to identify alternative materials and technologies to replace the properties of SF_6 in circuit breakers without the potential for GHG emissions; however no such material or technology has been developed as of this time.

The only technically feasible control technologies for SF_6 circuit breakers are the use of state-of-the-art, totally enclosed-pressure equipment equipped with leak detection systems. Totally enclosed-pressure systems can be guaranteed with a leakage rate less than 0.5% by weight per year. Density alarms can also be used in conjunction with such systems to identify SF_6 leaks quickly so that corrective actions can be taken in time to limit the release.

The use of enclosed-pressure SF_6 circuit breakers equipped with leak detection are the only technically feasible and available GHG control technologies for the Project. PVEC will employ such systems, which represent BACT for GHG for the Project.

SELECTION OF BACT

Given that PVEC has selected the top level of GHG emissions controls that are technically feasible for the Project, further ranking of technologies and analysis of costs is not required. BACT for GHG emissions from the Project is proposed to consist of the following:

1. Use of a Mitsubishi 501G AC combustion turbine operating in a combined cycle configuration.
2. Use of natural gas fuel at all times unless curtailed due to supply constraints, equipment failures or otherwise mandated by regulatory agency requirements[7].
3. Use of wet cooling technology to maximize overall system efficiency.
4. Using high-efficiency HVAC systems
5. Eliminating or reducing the amount of refrigerant used in HVAC systems
6. Incorporating window glazing to optimize heat loss
7. Incorporating super insulation to minimize heat loss
8. Incorporating motion sensors for lighting and climate control
9. Installing a water turbine in the cooling water supply line
10. Auxiliary boiler firing natural gas fuel, utilizing efficient combustion technology, and limited operation.
11. Emergency generator and fire pump firing ULSD fuel, with Tier 3 certified engines, and limited operation.
12. Use of state-of-the-art enclosed pressure SF_6 circuit breakers with leak detection.

I trust that this letter provides you with sufficient information at this time. Should you have any questions or require any further information, please contact me at 781-489-1146 or dfrecker@essgroup.com.

Sincerely,

ESS GROUP, INC.

Dammon M. Frecker
Vice President, Energy & Industrial Services

Attachment: Table 1 – Pioneer Valley Energy Center – Maximum Greenhouse Gas Emissions

C: M. Palmer, PVEC

[7] Under such conditions where natural gas is not available or where use of liquid fuel is mandated by regulatory agency requirements, the Project will use only Ultra Low Sulfur Distillate fuel oil.

Table 1
Pioneer Valley Energy Center
Maximum Greenhouse Gas Emissions

Stationary Source	Fuel Fired	Fuel Use Units	Annual Operation (hours)	Max Heat Input Rate (MMBtu/hr)	Fuel Heating Value (MMBtu/unit)	Max Fuel Firing Rate (unit/hr)	Max Annual Fuel Use (units/yr)	Annual Heat Input (MMBtu)
Combustion Turbine - normal operation	Natural Gas	cubic feet	7,320	2,542	0.001	2.54E+06	1.86E+10	1.86E+07
Combustion Turbine - normal operation	ULSD	gallons	1,440	2,016	0.138	1.46E+04	2.10E+07	2.90E+06
Auxiliary Boiler	Natural Gas	cubic feet	1,100	21.0	0.001	2.10E+04	2.31E+07	2.31E+04
Emergency Generator	Diesel Fuel	gallons	300	15.43	0.138	1.12E+02	3.35E+04	4.63E+03
Fire Pump	Diesel Fuel	gallons	300	1.89	0.138	1.37E+01	4.11E+03	5.67E+02

Stationary Source	Fuel Fired	GHG Emissions Factors (lbs/MMBtu)			Maximum GHG Emissions (tons CO2e)		
		CO2	CH4	N2O	Hourly	Daily	Annually
Combustion Turbine - normal operation	Natural Gas	129.7	0.0020	0.0062	167	4,016	1,224,893
Combustion Turbine - normal operation	ULSD	175.7	0.0066	0.0013	178	4,265	255,893
Auxiliary Boiler	Natural Gas	120.0	0.0020	0.0020	1.27	30.4	1,394
Emergency Generator	Diesel Fuel	165.0	0.0088	0.0013	1.28	30.7	383
Fire Pump	Diesel Fuel	164.0	0.0066	0.0013	0.16	3.7	47

Global Warming Potentials (The Climate Registry General Reporting Protocol, Table B.1)

CO2	1
CH4	21
N2O	310

GHG Emissions Factors References
Combustion Turbine (natural gas): CO2 (MHI), CH4 & N2O (GRP, Table 12.5)
Combustion Turbine (ULSD): CO2 (MHI), CH4 & N2O (CARB GHG Reporting Rule, Table 6)
Auxiliary Boiler: CO2 (AP-42, Table 1.4-2), CH4 & N2O (GRP, Table 12.5)
Emergency Generator: CO2 (AP-42, Table 3.4-1), CH4 (GRP, Table 12.5), N2O (CARB GHG Reporting Rule, Table 6)
Fire Pump: CO2 (AP-42, Table 3.3-1), CH4 & N2O (CARB GHG Reporting Rule, Table 6)